Horizontal Market Power in Wisconsin Electricity Markets:

A Report to

The Public Service Commission of Wisconsin

Appendices

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Appendix A. Input data and assumptions

This section summarizes the salient inputs to the TCA locational price-forecasting model (GE MAPS) for the midwestern part of the United States and, specifically, for the state of Wisconsin. The Midwest includes the following NERC regions: ECAR, FRCC, MAIN, MAPP, SERC, SPP and Ontario. Starting with the General Electric generation and transmission database for the Midwestern United States, TCA has verified, refined and/or replaced the data as appropriate, based on its own data sources and with data provided by the Public Service Commission of Wisconsin. We have included in-house analysis to ensure data integrity, validity, and consistency of plant operations with market developments.

The following is a list of the major data components, followed by a description of each component and the associated data sources:

(1) Load Inputs
(2) Thermal Unit Characteristics
(3) Planned Additions and Retirements
(4) Nuclear Unit Analysis
(5) Fuel Price Forecasts
(6) Transmission System Representation
(7) Environmental Regulations
(8) Conventional Hydro & Pumped Storage Units
(9) External Region Supply Curves
(10) NUG Contracts
(11) Dispatchable Demand (Interruptible Load)
(12) Market Model Assumptions

A.1 Load Inputs

Description*:* GE MAPS takes load inputs on an hourly basis (8760 per year) for every load serving entity. Loads for future years are scaled based on a forecast of annual peak demand and energy. GE MAPS adjusts the load profile in every year to account for the change in the day of the week at the start of every new year.

Data Sources*:* We use company's FERC 714 filings (1997) and EIA-411 (Load and Capability Report - 1999) from the relevant power pools for both the actual (1995) hourly loads (in EEI format) and the most recent available load forecast series from each power pool. A detailed load forecast for the relevant areas in MAIN is included in Section A.13.

A.2 Thermal Unit Characteristics

Description*:* GE MAPS models generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, etc.)
- Heat rate values and curve
- Summer and Winter Capacity
- Variable Operation and Maintenance costs (all values are in real 1999 $s)
- Fixed Operation and Maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs

We have developed heat rate curves for different units based on technology type and data points obtained from the data sources described below.

Data Sources*:* Our primary data source for generation characteristics is the 1998 NERC Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), capacity and heat rate data (heat rate data as of 1996). We use the 1998 NERC Generation Availability Data System (GADS) database as a reference for forced and unforced outage rates, which bases outage rates on plant type, size and vintage. We estimate operation and maintenance costs based on plant size, technology and age, and supplement our data with FERC Form 1 submissions, particularly for nuclear units. Fixed Operation and Maintenance (FOM) costs are based on FERC Form 1 historical data and represent averages values over three years, averaged by unit type and size units (FERC Form 1, average of years 1995 – 1997, tables: "Steam – Elec Gen Plant Stats (Large Plants)" and "Generating Plant Statistics (Small Plants)"). The resulting values are increased to account for general and administrative costs (around 20%), then reduced by a similar amount to account for competitive market response.

Fuel Switching Methodology*:* A number of generators have the ability to utilize a secondary fuel type. We have modeled this ability with the following methodology:

Natural Gas Primary: Units with natural gas as their primary fuel may burn fuel oil at most in one month of the year. Since our gas prices are highest in the month of January, we allow the unit to switch to fuel oil for the month of January, if the oil price at that location is lower than the natural gas price.

Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified. However we assume natural gas shortages prevent this from happening in the winter months (November – March). Also we assume a 3% heat rate degradation results when the unit switches to natural gas. Therefore we switch the fuels in any month from April-October when the price of natural gas plus 3% is less than the price of fuel oil.

A.3 Planned Additions and Retirements

***Description**:* Planned entry and retirements impact the fuel mix of installed capacity and composition of plants on the margin, since most retirements are oil or coal plants, which are likely to be replaced by combined cycle gas plants. New entry before 2004 is based on existing projects in development or projects in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge. After 2004, in addition to known projects, we add capacity based on economic criteria and market conditions. That is, we enter only as much capacity as is profitable.

Below is a list of planned new and expanding generating facilities in Wisconsin. There are no planned retirements in Wisconsin for the study period.

Planned New and Expanded Generating Facilities in Wisconsin

Pool	Owner	Year	Full Name	State	Type	Date	Capacity	Comment
MAIN	MGE	2000	West Marinette	WI	CTg	01Jun2000	93.2	
MAIN	WEPCO	2000	Germantown 5	WI	GTg	01Jan2000	95	
MAIN	WEPCO	2000	Neenah	WI	CTg	01Jun2000	350	
MAIN	WP&L	2000	WPL Substations	WI	ICo	01Jan2000	90	
MAPP	Dairyland Power	2001	Elk Mound 1	WI	GTgo	01Jun2001	48	
MAPP	Dairyland Power	2001	Elk Mound 2	WI	GTgo	01Jun2001	48	
MAIN	WEPCO	2001	Concord 1	WI	GTgo	01Jan2001	95	Upgrade
MAIN	WEPCO	2001	Concord 2	WI	GTgo	01Jan2001	95	Upgrade
MAIN	WEPCO	2001	Germantown 1	WI	GTg	01Jan2001	78	Upgrade
MAIN	WEPCO	2001	Germantown 2	WI	GTg	01Jan2001	78	Upgrade
MAIN	WEPCO	2001	Germantown 3	WI	GTg	01Jan2001	78	Upgrade
MAIN	WEPCO	2001	Germantown 4	WI	GTg	01Jan2001	78	Upgrade
MAIN	WP&L	2001	Addison	WI	WND	01Jan2001	30	
MAIN	Polsky	2001	RockGen	WI	CTg	01Jul2001	500	
MAIN	WEPCO	2001	Paris 1	WI	GTgo	01Jan2001	95	Upgrade
MAIN	WEPCO	2001	Paris 2	WI	GTgo	01Jan2001	95	Upgrade
MAIN	WEPCO	2002	Concord 3	WI	GTgo	01Jan2002	95	Upgrade
MAIN	WEPCO	2002	Concord 4	WI	GTgo	01Jan2002	95	Upgrade
MAIN	WEPCO	2002	Paris 3	WI	GTgo	01Jan2002	95	Upgrade
MAIN	WEPCO	2002	Paris 4	WI	GTgo	01Jan2002	95	Upgrade
MAIN	WP&L	2002	Rock River 7	WI	GTg	01Jun2002	150	
MAIN	WP&L	2002	Rock River 8	WI	GTg	01Jun2002	150	
MAIN	Manitowoc	2003	Manitowoc 7	WI	STc	01Jun2003	95	
MAIN	Badger	2003	Pleasant Prarie	WI	CCg	01Jun2003	524	
MAIN	Badger	2003	Pleasant Prarie	WI	CCg	01Jun2003	524	
MAIN	Polsky	2004	Depere Expansion	WI	CCg	01Jan2004	230	Upgrade

We track planned and announced retirements from power pool load and capacity reports as well as trade press announcements. Nuclear retirements are critical to the analysis and are discussed next. In addition, we monitor the profitability of units for every model run and retire those units that are not profitable, based on their performance in the model and external judgment about the likelihood of those plants improving profitability in later years.

Data Sources*:* Wisconsin Public Service Commission for units in Wisconsin. For the rest of the Midwest we use environmental permitting data from State Departments of Environmental Protection (DEP) as our primary source of planned projects that have a reasonably high degree of certainty. We also incorporate trade press announcements, power pool load and capacity reports and internal knowledge in our analysis to compile this list.

A.4 Nuclear Unit Analysis

Description*:* We use a combination of market knowledge, the Nuclear Regulatory Commission's (NRC) watch list and economic performance as reflected in model runs to determine whether any nuclear units should be retired prior to their license expiration. We use a four-year ('94-'97) average of O&M costs and revenue projections from model runs to assess units' economic performance. In the current analysis, the Zion units are assumed retired.

Data Sources*:* *NRC* (Nuclear Regulatory Commission), trade press announcements, FERC Form 1 data (for O&M costs) (FERC Form 1, average of years 1995 – 1997, tables: "Steam – Elec Gen Plant Stats (Large Plants)" and "Generating Plant Statistics (Small Plants)"), and announced retirements in power pool load and capacity reports are used.

A.5 Fuel Price Forecasts

Description*:* GE MAPS takes as input the monthly fuel price for each plant. We model fuel-switching capability of dual-fuel units and the seasonality of gas prices in order to accurately simulate dispatch behavior and cost. Our fundamental assumption of bidding behavior in competitive energy markets is that generators will bid in their marginal cost into the energy market. The marginal cost is the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. We therefore use forecasts of spot prices at regional hubs, and further refine these based on historical differentials between price points and their associated hubs. For oil and coal we use estimates of the price delivered to generators on a regional basis.

Data Sources*:* We use the Annual Energy Outlook 2000 (AEO-2000) as a source of the primary natural gas and oil price forecasts.

<u>Natural Gas</u>. We use AEO-2000 forecast of wellhead gas prices to which we add a historical differential between wellhead and Henry Hub. Next, we use the Gas Research Institute's (GRI) forecast of basis differential between Henry Hub and other specific hubs in the United States [GRI Baseline Projection Date Book, 2000 Edition, Vol.II, pp PRC 42]. Finally, we have historical data of monthly gas prices at every price point in the US for the last 9 years, which we use to develop differentials over the hub spot price on a locational basis [Gas Daily database].

Fuel Oil. We use AEO-2000 forecast of Refinery Acquisition Costs in the U.S. and an in-house regression model to estimate corresponding distillate and residual oil prices at the Boston Harbor location. Finally, we rely on GRI's forecast of price differentials for distillate and residual oil to electric generators between New England and each of the twelve oil price regions in the U.S., as well as of Canadian provinces [GRI Baseline Projection Date Book, 2000 Edition, Vol.II, pp PRC 37-38].

Coal. We use a plant-by-plant forecast of coal prices delivered to electric generators developed by RDI.

Wisconsin Fuel Prices (1999$)

Forecast Year:	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Natural Gas	$2.56	$2.60	$2.64	$2.68	$2.72	$2.77	$2.82	$2.87	$2.92	$2.98
Distillate Oil	$4.89	$4.88	$4.94	$4.95	$4.97	$5.01	$5.05	$5.10	$5.18	$5.16
Residual Oil	$3.42	$3.44	$3.46	$3.48	$3.49	$3.51	$3.53	$3.54	$3.56	$3.58

A.6 Transmission System Representation

***Description**:* We model the entire Midwest transmission system, including transformers, lines, phase shifters and buses. Most of the data are provided with GE MAPS in the form of a solved load flow case (PTI file). We identify and monitor potentially binding lines, interfaces and single-line-loss contingency constraints for the purpose of defining congestion zones and assessing congestion costs. GE provided the initial set of lines based on their contingency analysis. We verified, refined and added to this list of monitored transmission lines, interface and contingency definitions based on the data sources shown below.

***Data Sources**: We* use the following studies to refine and add to the transmission database provided by GE:

- FERC 715 filings and load flow cases (1998, 1999)
- NERC published total transfer capabilities and transmission studies (NERC 2000 Summer Assessment, Reliability of Bulk Electricity Supply in North America)
- MAIN 1999/00 Winter Transmission Assessment Study, MAIN 2000 Summer Transmission Assessment Study, MAIN 2002 Summer Future Systems Study
- Wisconsin Public Service Commission documents regarded transmission system upgrades

A.7 Environmental Regulations

***Description**:* We model both NO_x and SOx environmental regulations. We have added VOM values associated with scrubbers (SOx reduction) and NCRs (NOx reduction) to units that have already installed such equipment, and will incorporate these VOM values in the marginal cost bids. Further, we have added to the marginal cost bids the opportunity cost of SOx tradable permits for all units, based on their current emission rates, and current allowance trading prices. We have assumed the cost of SOx tradable permits to be $200/ton of Sulfur emission.

Current NOx Regulation: In 1997, the EPA issued the NO_x SIP (State Implementation Plan) Call, which would require 22 states and the District of Columbia in the Eastern U.S to submit plans to address the transport of ozone across state boundaries, primarily targeting utility and industrial boilers. This proposal followed in the footsteps of the Memorandum of Understanding (MOU) in the 12-state Northeast Ozone Transport Region (OTR), where states volunteered to reduce emissions to a level almost as stringent as the SIP Call by 2003, through institution of a cap-and-trade program. Under the SIP Call, each state, including states in the OTR, was assigned a budget for NO_x emissions based on an emission rate of 0.15 lb/MMBtu and projected levels of generation from existing electric generators. The total budget in the 22-state region is 544,000 tons, which represents an average reduction in seasonal NO_x emissions of over 60 percent by 2007. Originally, states were to file compliance plans by September 1999 and demonstrate attainment between 2003-2007. However, the D.C Circuit Court of Appeals ruling in May of 1999 suspended implementation of the SIP Call. Finally, on March 3, 2000 the same court largely upheld the SIP Call. The litigation was finally sealed on June 22, when the court denied re-hearing of the March 3rd decision. We therefore assume that implementation of the SIP Call will be delayed by one year to 2004.

Data Sources: We use EPA's Emission Inventory showing unit and plant heat input, NOx annual emissions and emission rates for power plants that are required to comply with the Acid Rain program. Capital costs for NOx abatement technology were obtained from EPA's Regulatory Impact Assessment report for the NOx Budget Program, originally provided by Bechtel Corporation.

A.8 Conventional Hydro and Pumped Storage Units

Description: GE MAPS has special provisions for modeling hydro units. These data do not require any significant analysis or manipulation, except to provide seasonal patterns of water flow for conventional hydro units.

Data Sources*: ES&D* database is used for all hydro unit information. Data provided by the Wisconsin Public Service Commission were used for Wisconsin hydro units.

A.9 External Region Supply Curves

The model explicitly models the full Midwest system, including imports from Manitoba, Saskatchewan, and the Northeast. The interaction with regions outside this study area is modeled as a series of thermal units. The thermal capacities of these representational units determine either the maximum export capability across tie lines to the Northeast, or the maximum generation capacity available for export from the outside area. We use historic exports, combined with our expectation of future conditions in these areas, to project export levels and prices for each of the forecast years.

Data Sources*:* We use Load, Capacity, Energy, Fuels and Transmission Report, Northeast Power Coordinating Council (NPCC), 1998, Electricity Exports and Imports, National Energy Board, Canada, 1997.

A.10 NUG Contracts

Description*:* We model all Non-Utility Generation units effectively as must-run units in the short term by assigning them a very low fuel cost. We include all NUGs in the Midwest. Recently, there have been many market and structural changes that affect these contracts and many utilities are considering or are in the process of re-negotiation of these contracts. If the re-negotiations are successful then the associated generation units will run based on their economics only and thus become dispatchable. We assume all the NUGs in the Midwest will be dispatchable after 2003.

A.11 Dispatchable Demand (Interruptible Load)

Description*:* We include in our modeling a representation of interruptible load to capture the effects on electricity prices. The presence of demand response is important to the energy and installed capacity prices. In the energy market the value of energy to interruptible load caps the prices and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value.

We spread this dispatchable demand among companies based on their load share of the total system load (unless we have more detailed information). The dispatchable demand units are modeled as generators with a dispatch price of $600/MWh for the first block (50% of company’s dispatchable demand) and $800/Mwh for the second block. These units rarely run in our model, as the high energy prices they require are assumed to indicate a supply shortfall and prompt new entry to meet the local demand. These units play an insignificant role in the energy market, but an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When these units are included in the calculation of the required reserve margin they reduce the requirement of installed capacity and thus reduce the new entry and help increase the energy prices consistent with market behavior.

Data Sources*:* We used interruptible load values based on NERC EIA-411 filings (1999). These data are subject to some uncertainty as utilities report a combination of interruptible load and Demand Side Management reduction in peak load and total energy. We then distribute the interruptible load uniformly among the Load Serving Entities.

A.12 Market Model Assumptions

Marginal Cost Bidding: We assume all generation units bid marginal cost (opportunity cost of fuel plus VOM plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus our prices tend to underestimate the prices in the real markets.

Installed Capacity: The installed capacity requirements are shown in the "Pools Capacity Balance" table in section A.13.

ISO Boundaries: The unit commitment, dispatch and reserve requirements are maintained on a geographic basis considering the whole of the Midwest as an ISO. The imports/exports between the ISO and neighboring systems reflect economy energy purchase/sales and incur wheeling charges. Transactions within the ISO boundary do not incur any transmission charge (we assumed selling/buying from the pool, and the load pays the transmission charge irrespective where it buys its energy from within the pool).

Operating Reserves (spinning and standby): The operating reserves are based on the specific requirements instituted by each NERC region. These requirements are based on the loss of the largest single generator or the largest single generator and half the second largest generator. The spinning reserves market affects the energy market prices since the units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled.

A.13 Load and Energy forecast

Wisconsin Load and Energy Forecast by Company

Company	Peak Load 2001 (MW)	Total Energy 2001 (GWh)	Peak Load 2002 (MW)	Total Energy 2002 (GWh)	Peak Load 2003 (MW)	Total Energy 2003 (GWh)	Peak Load 2004 (MW)	Total Energy 2004 (GWh)	Peak Load 2005 (MW)	Total Energy 2005 (GWh)
Madison Gas & Electric	673	3,107	687	3,180	702	3,255	718	3,333	734	3,431
Upper Penninsula Power	144	893	145	902	146	911	147	921	148	930
Wisconsin Electric Power	5,646	30,704	5,775	31,290	5,904	31,875	6,034	32,459	6,182	33,221
Wisconsin Power and Light	2,327	12,441	2,384	12,748	2,430	12,996	2,487	13,302	2,542	13,592
Wisconsin Public Service	1,899	11,817	1,881	11,972	1,891	12,162	1,902	12,356	1,913	12,546
Wisconsin Public Power	556	3,450	569	3,526	582	3,604	595	3,678	607	3,753

Wisconsin Load and Energy Forecast by Company

Company	Peak Load 2006 (MW)	Total Energy 2006 (GWh)	Peak Load 2007 (MW)	Total Energy 2007 (GWh)	Peak Load 2008 (MW)	Total Energy 2008 (GWh)	Peak Load 2009 (MW)	Total Energy 2009 (GWh)	Peak Load 2010 (MW)	Total Energy 2010 (GWh)
Madison Gas & Electric	750	3,534	767	3,563	782	3,634	798	3,706	814	3,780
Upper Penninsula Power	149	940	150	949	150	959	151	969	152	978
Wisconsin Electric Power	6,301	33,806	6,425	34,474	6,572	35,150	6,721	35,839	6,875	36,542
Wisconsin Power and Light	2,579	13,794	2,608	13,944	2,657	14,199	2,707	14,459	2,758	14,724
Wisconsin Public Service	1,922	12,738	1,932	12,922	1,942	13,098	1,952	13,277	1,963	13,458
Wisconsin Public Power	620	3,820	635	3,907	650	3,996	666	4,088	682	4,181

Pool Capacity Balance												
Pool	**Category**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
MAIN	Total Internal Demand	48,542	49,135	49,763	50,505	51,362	52,249	53,059	53,747	54,606	55,410	56,226
	Interruptible Demand	2,377	2,433	2,450	2,457	2,464	2,469	2,472	2,477	2,482	2,482	2,482
	Net Internal Demand	46,165	46,702	47,313	48,048	48,898	49,780	50,587	51,270	52,124	52,928	53,744
	Reserve Margin %	15	15	15	15	15	15	15	15	15	15	15
	Load + Reserve	53,090	53,707	54,410	55,255	56,233	57,247	58,175	58,961	59,943	60,867	61,806
	Purchases	3,617	4,126	3,545	3,985	4,175	4,540	4,688	4,385	4,911	4,911	4,911
	Sales	1,970	1,122	1,001	786	757	724	410	350	330	330	330
	EIA411 Capacity	51,960	51,972	53,432	53,768	54,413	54,824	55,373	56,621	56,535	56,535	56,535
	New Entry	1,619	1,484	2,682	752	0	0	0	0	460	460	0
	Retirement	212	342	0	0	137	0	0	0	0	0	0
	MAPS Capacity	52,814	54,545	56,885	57,637	57,637	57,500	57,500	57,500	57,960	58,420	58,420
	Balance	**1,371**	**3,842**	**5,019**	**5,581**	**4,822**	**4,069**	**3,603**	**2,575**	**2,598**	**2,134**	**1,195**

Appendix B. Structural Analysis Results

The following tables present the HHI results for all utility service territories in Wisconsin.

B.1 Economic Capacity Test Results

B.1.1 HHI for EC Test: Wisconsin Public Power Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,134	2,216	1,875	2,152	2,165	2,088	2,116	2,235	1,854
2002	2,244	2,292	1,868	2,120	2,135	2,313	2,250	2,396	1,852
2003	1,901	2,150	1,862	2,068	2,000	2,143	1,993	1,969	1,776
2004	1,647	1,974	1,420	1,791	1,649	1,710	1,632	1,709	1,873
2005	1,660	1,968	1,374	1,804	1,682	1,701	1,883	1,735	1,711
2006	1,630	1,788	1,381	1,766	1,642	1,668	1,700	1,719	1,370
2007	1,647	1,783	1,375	1,766	1,622	1,709	1,674	1,703	1,376

B.1.2 HHI for EC Test: Upper Peninsula Power Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,143	2,236	1,553	2,180	2,187	3,006	2,159	2,366	1,549
2002	2,376	2,474	1,547	2,157	2,103	2,229	2,268	2,773	1,546
2003	1,987	2,226	1,543	2,078	1,958	2,207	1,961	2,092	1,466
2004	1,695	2,036	1,370	1,791	1,695	2,260	1,749	2,018	1,637
2005	1,718	1,957	1,303	1,662	1,691	2,225	1,690	2,174	1,304
2006	1,681	1,933	1,303	1,661	1,687	2,228	1,710	1,997	1,268
2007	1,710	1,928	1,298	1,821	1,646	2,205	1,712	1,966	1,265

B.1.3 HHI for EC Test: Wisconsin Power & Light Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,076	1,937	2,027	2,139	2,145	2,282	1,961	2,190	1,787
2002	1,992	2,351	1,885	2,133	2,167	2,208	2,241	2,235	1,863
2003	1,931	1,933	1,732	2,008	2,035	2,041	1,937	1,946	1,735
2004	1,724	1,675	1,354	1,772	1,627	1,839	1,650	1,702	1,728
2005	1,914	1,699	1,672	1,726	1,631	1,827	1,653	1,769	1,708
2006	1,768	1,665	1,649	1,723	1,635	1,830	1,627	1,694	1,645
2007	1,623	1,661	1,645	1,757	1,632	1,815	1,664	1,689	1,640

B.1.4 HHI for EC Test: Madison Gas & Electric Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,090	1,967	2,230	2,155	2,161	2,373	2,116	2,227	2,325
2002	1,932	2,355	2,605	2,147	2,153	2,318	2,094	2,395	2,602
2003	2,014	1,977	2,252	2,073	2,078	2,158	1,953	1,974	2,256
2004	1,782	1,716	1,861	1,774	1,707	1,886	1,804	1,718	1,827
2005	1,661	1,930	1,917	1,769	1,700	1,878	1,713	1,726	1,337
2006	1,672	1,703	1,800	1,769	1,768	1,872	1,674	1,703	1,372
2007	1,769	1,668	1,795	1,768	1,764	1,857	1,627	1,706	1,994

B.1.5 HHI for EC Test: Wisconsin Public Service Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,084	2,133	1,875	2,153	2,168	2,144	2,142	2,168	1,910
2002	1,976	2,314	1,129	2,144	1,995	2,435	2,250	2,104	1,115
2003	2,018	2,194	1,906	2,066	1,944	1,782	1,946	1,960	1,112
2004	1,786	1,975	1,455	1,784	1,689	1,687	1,709	1,813	1,418
2005	1,644	1,887	1,398	1,752	1,684	1,675	1,681	1,699	1,373
2006	1,810	1,960	1,399	1,748	1,679	1,684	1,707	1,852	1,392
2007	1,761	1,955	925	1,736	1,675	1,669	1,672	1,872	1,374

B.1.6 HHI for EC Test: Wisconsin Electric Power Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,116	2,144	2,901	2,182	2,187	2,295	1,993	2,184	2,913
2002	1,994	2,405	3,088	2,172	2,188	2,551	2,023	2,295	3,083
2003	2,155	1,975	2,881	2,094	2,111	2,166	1,980	1,981	2,792
2004	1,811	1,710	2,298	1,799	1,742	1,799	1,818	1,717	2,234
2005	1,828	1,741	2,223	1,799	1,739	1,793	1,690	1,713	2,271
2006	1,685	1,702	2,214	1,796	1,804	1,788	1,748	1,709	2,210
2007	1,680	1,681	2,260	1,793	1,801	1,732	1,683	1,701	2,203

B.1.7 HHI for EC Test: Northern States Power (WI) Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	848	861	1,263	867	871	859	876	853	966
2002	819	877	1,225	869	828	892	872	871	944
2003	816	860	1,174	849	829	919	823	821	934
2004	812	859	1,090	844	817	926	807	852	889
2005	822	858	1,070	837	823	924	857	822	887
2006	874	867	1,077	882	845	914	853	868	1,034
2007	879	879	1,054	897	884	914	877	856	1,018

B.2 Available Economic Capacity Test Results

B.2.1 HHI for AEC Test: Wisconsin Public Power Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,334	2,430	2,215	2,307	2,322	2,344	2,314	2,455	2,179
2002	2,466	2,540	2,209	2,284	2,301	2,630	2,474	2,646	2,177
2003	2,041	2,368	2,203	2,204	2,149	2,416	2,170	2,142	2,066
2004	1,740	2,127	1,572	1,882	1,752	1,847	1,729	1,827	2,050
2005	1,769	2,121	1,525	1,898	1,797	1,838	2,032	1,856	1,880
2006	1,724	1,917	1,530	1,854	1,745	1,808	1,818	1,840	1,517
2007	1,740	1,913	1,524	1,854	1,719	1,849	1,787	1,822	1,522

B.2.2 HHI for AEC Test: Upper Peninsula Power Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,309	2,456	1,829	2,341	2,349	3,557	2,366	2,652	1,823
2002	2,621	2,763	1,822	2,310	2,281	2,746	2,497	3,198	1,818
2003	2,163	2,467	1,815	2,217	2,112	2,725	2,131	2,348	1,745
2004	1,793	2,201	1,444	1,890	1,811	2,519	1,873	2,192	1,838
2005	1,837	2,121	1,377	1,759	1,808	2,482	1,805	2,421	1,377
2006	1,795	2,082	1,375	1,761	1,803	2,484	1,830	2,198	1,341
2007	1,830	2,078	1,371	1,918	1,751	2,461	1,832	2,137	1,337

B.2.3 HHI for AEC Test: Wisconsin Power & Light Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,215	2,099	2,282	2,291	2,299	2,513	2,129	2,404	2,071
2002	2,146	2,590	2,199	2,283	2,324	2,475	2,463	2,471	2,179
2003	2,094	2,097	2,003	2,156	2,175	2,274	2,102	2,118	2,008
2004	1,816	1,786	1,483	1,859	1,721	1,984	1,757	1,819	1,880
2005	2,060	1,816	1,829	1,815	1,724	1,975	1,762	1,898	1,860
2006	1,852	1,776	1,791	1,812	1,727	1,976	1,723	1,811	1,787
2007	1,726	1,772	1,787	1,851	1,724	1,957	1,776	1,807	1,782

B.2.4 HHI for AEC Test: Madison Gas & Electric Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	2,232	2,136	2,535	2,310	2,318	2,626	2,281	2,448	2,661
2002	2,095	2,598	3,028	2,299	2,308	2,617	2,256	2,649	3,024
2003	2,141	2,151	2,565	2,209	2,217	2,426	2,122	2,150	2,570
2004	1,868	1,834	2,037	1,862	1,802	2,041	1,896	1,838	2,000
2005	1,755	2,078	2,111	1,858	1,796	2,032	1,833	1,848	1,484
2006	1,785	1,821	1,969	1,859	1,865	2,027	1,788	1,822	1,513
2007	1,855	1,781	1,965	1,858	1,862	2,008	1,723	1,825	2,203

B.2.5 HHI for AEC Test: Wisconsin Public Service Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,226	2,334	2,215	2,308	2,327	2,412	2,344	2,390	2,279
2002	2,127	2,562	1,361	2,294	2,168	2,835	2,474	2,343	1,353
2003	2,146	2,414	2,273	2,202	2,097	2,081	2,113	2,171	1,350
2004	1,873	2,128	1,611	1,874	1,803	1,829	1,827	1,958	1,570
2005	1,735	2,035	1,554	1,847	1,799	1,817	1,795	1,837	1,523
2006	1,902	2,111	1,554	1,842	1,793	1,831	1,826	2,000	1,547
2007	1,853	2,107	1,000	1,829	1,789	1,810	1,786	2,021	1,522

B.2.6 HHI for AEC Test: Wisconsin Electric Power Service Territory

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,258	2,342	3,387	2,336	2,343	2,521	2,157	2,389	3,404
2002	2,165	2,649	3,628	2,323	2,343	2,848	2,201	2,523	3,624
2003	2,299	2,142	3,367	2,231	2,250	2,374	2,149	2,151	3,255
2004	1,899	1,824	2,558	1,887	1,840	1,927	1,916	1,832	2,484
2005	1,960	1,860	2,472	1,889	1,836	1,922	1,789	1,828	2,531
2006	1,795	1,815	2,463	1,886	1,902	1,916	1,845	1,824	2,459
2007	1,774	1,792	2,512	1,883	1,899	1,853	1,781	1,816	2,451

B.2.7 HHI for AEC Test: Northern States Power (WI) Service Territory

	Winter			Summer			Shoulder		
Year	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**	**Super-Peak**	**Peak**	**Off-Peak**
2001	836	848	1,235	855	859	848	864	841	953
2002	807	865	1,198	858	816	880	860	858	931
2003	804	847	1,148	838	817	906	811	809	921
2004	801	846	1,069	832	805	912	795	840	877
2005	810	846	1,050	825	812	911	844	811	875
2006	861	855	1,056	870	832	901	841	856	1,015
2007	866	867	1,034	884	872	901	865	844	1,002

Appendix C. Illustrative Example of Strategic Bidding

Appendix C

Illustrative Example of Strategic Bidding: Input Data

Supply

Firm 1		
Unit #	Capacity (MW)	Variable Cost ($/MWh)
1	1000	$ 10.00
4	300	$ 25.00
5	100	$ 30.00
Total	1400	

Firm # 2		
Unit #	Capacity (MW)	Variable Cost ($/MWh)
2	380	$ 15.00
3	320	$ 18.00
6	60	$ 32.00
	760	

Demand		
Peak hour	2,130	MW
Mid hour	1,850	MW
Low hour	1,540	MW

Bidding strategies **Production Cost Bidding (PCB) vs. Strategic Bidding (SB)**

Unit #	Cumulative Capacity	**PCB** Bid_Price	**SB** Bid_Price	Basis= Var.Cost	Plus impacts of other units on bid price of each unit 1	2	3	4	5	6
1	1000	$ 10.00	$ 21.79	$ 10.00	$ -	$ 3.84	$ 1.94	$ 2.22	$ 2.72	$ 1.06
2	1380	$ 15.00	$ 25.46	$ 15.00	$ -	$ -	$ 2.53	$ 3.01	$ 3.54	$ 1.39
3	1700	$ 18.00	$ 27.73	$ 18.00	$ -	$ -	$ -	$ 3.88	$ 4.20	$ 1.64
4	2000	$ 25.00	$ 31.68	$ 25.00	$ -	$ -	$ -	$ -	$ 4.80	$ 1.88
5	2100	$ 30.00	$ 31.95	$ 30.00	$ -	$ -	$ -	$ -	$ -	$ 1.95
6	2160	$ 32.00	$ 32.00	$ 32.00	$ -	$ -	$ -	$ -	$ -	$ -

Bid_price of each unit under SB equals the sum of variable cost plus impacts of other units on the bid price

Computation of the Bid Price under SB is based on a simplified version of bidding algorithm implemented in COMPEL

Illustrative Example of Strategic Bidding: Summary of Results

High Load Hour

Profit Margin of Firm 1

	Strategy of Firm 2	
Strategy of Firm 1	PCB	SB
PCB	$ 24,300	$ 24,300
SB	$ 24,300	**$ 24,300**

Profit Margin of Firm 2

	Strategy of Firm 2	
Strategy of Firm 1	**PCB**	**SB**
PCB	$ 10,940	$ 10,940
SB	$ 10,940	**$ 10,940**

Mid Load Hour

Profit Margin of Firm 1

	Strategy of Firm 2	
Strategy of Firm 1	PCB	SB
PCB	$ 15,000	$ 18,548
SB	$ 22,684	**$ 22,684**

Profit Margin of Firm 2

	Strategy of Firm 2	
Strategy of Firm 1	**PCB**	**SB**
PCB	$ 6,040	$ 6,491
SB	$ 10,717	**$ 10,717**

Low Load Hour

Profit Margin of Firm 1

	Strategy of Firm 2	
Strategy of Firm 1	PCB	SB
PCB	$ 8,000	$ 15,604
SB	$ 9,901	**$ 17,729**

Profit Margin of Firm 2

	Strategy of Firm 2	
Strategy of Firm 1	**PCB**	**SB**
PCB	$ 1,140	$ 2,511
SB	$ 3,791	**$ 6,394**

Profit Margin = (Revenues - Variable Cost)

Appendix C

High Load Hour **2130** MW

Firm 1	**PCB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 15.00
	4	300	$ 25.00		3	320	$ 18.00
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 32.00	$ 32,000	$ 32,000	
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 32.00	$ 12,160		$ 12,160
3	$ 18.00	320	$ 18.00	$ 5,760		$ 5,760	$ 32.00	$ 10,240		$ 10,240
4	$ 25.00	300	$ 25.00	$ 7,500	$ 7,500		$ 32.00	$ 9,600	$ 9,600	
5	$ 30.00	100	$ 30.00	$ 3,000	$ 3,000		$ 32.00	$ 3,200	$ 3,200	
6	$ 32.00	30	$ 32.00	$ 960		$ 960	$ 32.00	$ 960		$ 960
Total		2130		$ 32,920	$ 20,500	$ 11,460		$ 68,160	$ 44,800	$ 22,400
Profit Margin								$ 35,240	$ 24,300	$ 10,940

Firm 1	**SB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 25.46
	4	300	$ 31.68		3	320	$ 27.73
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 21.79	1000	$ 10.00	$ 10,000	$ 10,000	$ -	$ 32.00	$ 32,000	$ 32,000	
2	$ 25.46	380	$ 15.00	$ 5,700	$ -	$ 5,700	$ 32.00	$ 12,160		$ 12,160
3	$ 27.73	320	$ 18.00	$ 5,760	$ -	$ 5,760	$ 32.00	$ 10,240		$ 10,240
4	$ 31.68	300	$ 25.00	$ 7,500	$ 7,500	$ -	$ 32.00	$ 9,600	$ 9,600	
5	$ 31.95	100	$ 30.00	$ 3,000	$ 3,000	$ -	$ 32.00	$ 3,200	$ 3,200	
6	$ 32.00	30	$ 32.00	$ 960	$ -	$ 960	$ 32.00	$ 960		$ 960
Total		2130		$ 32,920	$ 20,500	$ 12,420		$ 68,160	$ 44,800	$ 23,360
Profit Margin								$ 35,240	$ 24,300	$ 10,940

Appendix C

Firm 1	**PCB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 25.46
	4	300	$ 25.00		3	320	$ 27.73
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 32.00	$ 32,000	$ 32,000	
4	$ 25.00	300	$ 25.00	$ 7,500	$ 7,500		$ 32.00	$ 9,600	$ 9,600	
2	$ 25.46	380	$ 15.00	$ 5,700		$ 5,700	$ 32.00	$ 12,160		$ 12,160
3	$ 27.73	320	$ 18.00	$ 5,760		$ 5,760	$ 32.00	$ 10,240		$ 10,240
5	$ 30.00	100	$ 30.00	$ 3,000	$ 3,000		$ 32.00	$ 3,200	$ 3,200	
6	$ 32.00	30	$ 32.00	$ 960		$ 960	$ 32.00	$ 960		$ 960
Total		2130		$ 32,920	$ 20,500	$ 12,420		$ 68,160	$ 44,800	$ 23,360
Profit Margin								$ 35,240	$ 24,300	$ 10,940

Firm 1	**SB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 15.00
	4	300	$ 31.68		3	320	$ 18.00
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 32.00	$ 12,160		$ 12,160
3	$ 18.00	320	$ 18.00	$ 5,760		$ 5,760	$ 32.00	$ 10,240		$ 10,240
1	$ 21.79	1000	$ 10.00	$ 10,000	$ 10,000		$ 32.00	$ 32,000	$ 32,000	
4	$ 31.68	300	$ 25.00	$ 7,500	$ 7,500		$ 32.00	$ 9,600	$ 9,600	
5	$ 31.95	100	$ 30.00	$ 3,000	$ 3,000		$ 32.00	$ 3,200	$ 3,200	
6	$ 32.00	30	$ 32.00	$ 960		$ 960	$ 32.00	$ 960		$ 960
Total		2130		$ 32,920	$ 20,500	$ 12,420		$ 68,160	$ 44,800	$ 23,360
Profit Margin								$ 35,240	$ 24,300	$ 10,940

Appendix C

Mid Load Hour **1850** MW

Firm 1	**PCB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 15.00
	4	300	$ 25.00		3	320	$ 18.00
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 25.00	$ 25,000	$ 25,000	
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 25.00	$ 9,500		$ 9,500
3	$ 18.00	320	$ 18.00	$ 5,760		$ 5,760	$ 25.00	$ 8,000		$ 8,000
4	$ 25.00	150	$ 25.00	$ 3,750	$ 3,750		$ 25.00	$ 3,750	$ 3,750	
Total		1850		$ 25,210	$ 13,750	$ 11,460		$ 46,250	$ 28,750	$ 17,500
Profit Margin								$ 21,040	$ 15,000	$ 6,040

Firm 1	**SB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 25.46
	4	300	$ 31.68		3	320	$ 27.73
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 21.79	1000	$ 10.00	$ 10,000	$ 10,000	$ -	$ 31.68	$ 31,682	$ 31,682	
2	$ 25.46	380	$ 15.00	$ 5,700	$ -	$ 5,700	$ 31.68	$ 12,039		$ 12,039
3	$ 27.73	320	$ 18.00	$ 5,760	$ -	$ 5,760	$ 31.68	$ 10,138		$ 10,138
4	$ 31.68	150	$ 25.00	$ 3,750	$ 3,750	$ -	$ 31.68	$ 4,752	$ 4,752	
Total		1850		$ 25,210	$ 13,750	$ 11,460		$ 58,611	$ 36,434	$ 22,177
Profit Margin								$ 33,401	$ 22,684	$ 10,717

Appendix C

Firm 1	**PCB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 25.46
	4	300	$ 25.00		3	320	$ 27.73
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 27.73	$ 27,729	$ 27,729	
4	$ 25.00	300	$ 25.00	$ 7,500	$ 7,500		$ 27.73	$ 8,319	$ 8,319	
2	$ 25.46	380	$ 15.00	$ 5,700		$ 5,700	$ 27.73	$ 10,537		$ 10,537
3	$ 27.73	170	$ 18.00	$ 3,060		$ 3,060	$ 27.73	$ 4,714		$ 4,714
Total		1850		$ 26,260	$ 17,500	$ 8,760		$ 51,299	$ 36,048	$ 15,251
Profit Margin								$ 25,039	$ 18,548	$ 6,491

Firm 1	**SB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 15.00
	4	300	$ 31.68		3	320	$ 18.00
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 31.68	$ 12,039		$ 12,039
3	$ 18.00	320	$ 18.00	$ 5,760		$ 5,760	$ 31.68	$ 10,138		$ 10,138
1	$ 21.79	1000	$ 10.00	$ 10,000	$ 10,000		$ 31.68	$ 31,682	$ 31,682	
4	$ 31.68	150	$ 25.00	$ 3,750	$ 3,750		$ 31.68	$ 4,752	$ 4,752	
Total		1850		$ 25,210	$ 13,750	$ 11,460		$ 58,611	$ 36,434	$ 22,177
Profit Margin								$ 33,401	$ 22,684	$ 10,717

Appendix C

Low Load Hour **1540** MW

Firm 1	**PCB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 15.00
	4	300	$ 25.00		3	320	$ 18.00
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 18.00	$ 18,000	$ 18,000	
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 18.00	$ 6,840		$ 6,840
3	$ 18.00	160	$ 18.00	$ 2,880		$ 2,880	$ 18.00	$ 2,880		$ 2,880
Total		1540		$ 18,580	$ 10,000	$ 8,580		$ 27,720	$ 18,000	$ 9,720
Profit Margin								$ 9,140	$ 8,000	$ 1,140

Firm 1	**SB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 25.46
	4	300	$ 31.68		3	320	$ 27.73
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 21.79	1000	$ 10.00	$ 10,000	$ 10,000	$ -	$ 27.73	$ 27,729	$ 27,729	
2	$ 25.46	380	$ 15.00	$ 5,700	$ -	$ 5,700	$ 27.73	$ 10,537		$ 10,537
3	$ 27.73	160	$ 18.00	$ 2,880	$ -	$ 2,880	$ 27.73	$ 4,437		$ 4,437
Total		1540		$ 18,580	$ 10,000	$ 8,580		$ 42,703	$ 27,729	$ 14,974
Profit Margin								$ 24,123	$ 17,729	$ 6,394

Appendix C

Firm 1	**PCB**
Firm 2	**SB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 10.00		2	380	$ 25.46
	4	300	$ 25.00		3	320	$ 27.73
	5	100	$ 30.00		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
1	$ 10.00	1000	$ 10.00	$ 10,000	$ 10,000		$ 25.46	$ 25,464	$ 25,464	
4	$ 25.00	300	$ 25.00	$ 7,500	$ 7,500		$ 25.46	$ 7,639	$ 7,639	
2	$ 25.46	240	$ 15.00	$ 3,600		$ 3,600	$ 25.46	$ 6,111		$ 6,111
Total		1540		$ 21,100	$ 17,500	$ 3,600		$ 39,215	$ 33,104	$ 6,111
Profit Margin								$ 18,115	$ 15,604	$ 2,511

Firm 1	**SB**
Firm 2	**PCB**

Bids:

Firm 1	Unit	Capacity	Bid price	**Firm 2**	Unit	Capacity	Bid price
	1	1000	$ 21.79		2	380	$ 15.00
	4	300	$ 31.68		3	320	$ 18.00
	5	100	$ 31.95		6	60	$ 32.00

Dispatch:

Units Dispatched	Bid Price	Capacity dispatched	Variable Cost	**Costs**	Firm 1	Firm 2	**MCP**	**Revenues**	Firm 1	Firm 2
2	$ 15.00	380	$ 15.00	$ 5,700		$ 5,700	$ 21.79	$ 8,279		$ 8,279
3	$ 18.00	320	$ 18.00	$ 5,760		$ 5,760	$ 21.79	$ 6,972		$ 6,972
1	$ 21.79	840	$ 10.00	$ 8,400	$ 8,400		$ 21.79	$ 18,301	$ 18,301	
Total		1540		$ 19,860	$ 8,400	$ 11,460		$ 33,551	$ 18,301	$ 15,251
Profit Margin								$ 13,691	$ 9,901	$ 3,791

Appendix D. Behavioral Analysis Results: PCMI by Scenario

WUMS Base Case PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	22.99%	36.38%	29.54%	54.32%	99.87%	76.61%
2	20.86%	33.26%	26.70%	47.31%	85.57%	65.34%
3	26.78%	34.38%	30.41%	52.69%	78.40%	64.96%
4	24.69%	32.20%	28.26%	46.45%	75.58%	60.29%
5	20.18%	29.33%	24.66%	34.76%	63.51%	48.83%
6	23.59%	32.80%	28.04%	39.42%	70.83%	54.61%
7	24.85%	30.22%	27.49%	46.93%	70.18%	58.37%
8	22.41%	26.76%	24.62%	42.23%	64.78%	53.69%
9	25.84%	32.66%	28.96%	46.68%	78.57%	61.26%
10	27.14%	37.24%	32.23%	54.02%	93.94%	74.15%
11	18.49%	29.87%	24.06%	37.97%	79.36%	58.23%
12	17.49%	25.54%	21.12%	33.78%	71.96%	50.98%
Total	22.90%	31.63%	27.12%	44.56%	77.39%	60.42%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	24.41%	39.56%	31.95%	55.01%	92.88%	73.88%
2	19.24%	33.67%	26.00%	42.95%	81.85%	61.18%
3	14.35%	25.81%	19.46%	30.33%	58.46%	42.89%
4	13.27%	24.22%	18.58%	27.02%	58.51%	42.30%
5	17.81%	26.49%	22.05%	32.69%	56.42%	44.28%
6	20.72%	27.52%	23.88%	37.84%	63.83%	49.91%
7	24.56%	29.51%	27.09%	44.96%	67.66%	56.55%
8	22.89%	29.62%	26.19%	41.00%	62.56%	51.58%
9	15.23%	29.03%	21.69%	32.94%	65.83%	48.35%
10	17.51%	32.76%	25.15%	37.46%	74.52%	56.02%
11	19.04%	34.78%	26.39%	44.45%	80.69%	61.38%
12	18.03%	30.43%	23.91%	38.05%	73.53%	54.88%
Total	19.06%	30.38%	24.51%	38.88%	69.83%	53.77%

WUMS Base Case PCMI 2003-2004						
2003	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	25.47%	42.56%	33.83%	51.88%	97.70%	74.31%
2	23.10%	36.17%	29.32%	47.71%	89.97%	67.83%
3	15.34%	24.31%	19.36%	28.29%	65.47%	44.97%
4	14.00%	23.76%	18.74%	24.50%	59.04%	41.30%
5	16.83%	24.69%	20.57%	28.47%	54.57%	40.87%
6	15.19%	19.07%	17.06%	22.96%	38.65%	30.51%
7	18.32%	20.02%	19.17%	30.45%	45.37%	37.95%
8	16.55%	18.09%	17.26%	26.30%	42.30%	33.72%
9	12.82%	19.35%	16.03%	18.70%	43.27%	30.78%
10	14.78%	21.57%	18.20%	29.22%	51.31%	40.37%
11	13.80%	22.89%	17.84%	26.26%	56.46%	39.70%
12	12.19%	18.08%	15.10%	19.77%	44.35%	31.94%
Total	16.54%	24.05%	20.15%	29.50%	56.80%	42.62%

2004	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	10.35%	17.46%	13.67%	14.19%	23.39%	18.48%
2	8.63%	15.33%	11.70%	12.28%	21.34%	16.43%
3	7.93%	14.10%	10.96%	10.68%	21.13%	15.81%
4	7.33%	13.03%	10.11%	9.56%	20.66%	14.97%
5	9.35%	13.69%	11.32%	12.11%	21.00%	16.15%
6	11.45%	13.25%	12.37%	14.26%	19.86%	17.11%
7	13.20%	13.38%	13.29%	16.77%	21.83%	19.29%
8	11.82%	14.00%	12.90%	14.91%	22.02%	18.42%
9	9.98%	15.18%	12.52%	13.51%	22.31%	17.81%
10	8.99%	15.58%	11.98%	11.30%	22.88%	16.55%
11	9.47%	15.60%	12.45%	12.15%	23.10%	17.48%
12	8.81%	14.51%	11.61%	10.41%	21.51%	15.87%
Total	9.89%	14.53%	12.13%	12.82%	21.73%	17.11%

WUMS Base Case PCMI 2005-2006						
2005	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	11.39%	15.31%	13.15%	20.60%	54.44%	35.85%
2	8.84%	14.74%	11.62%	12.77%	29.81%	20.79%
3	8.70%	13.85%	11.21%	8.82%	14.31%	11.49%
4	7.89%	13.28%	10.38%	9.24%	13.48%	11.20%
5	6.31%	8.29%	7.25%	16.03%	21.09%	18.43%
6	6.71%	6.17%	6.44%	11.29%	11.27%	11.28%
7	7.63%	7.34%	7.50%	13.38%	14.56%	13.92%
8	6.80%	8.05%	7.43%	12.87%	15.62%	14.24%
9	3.19%	3.94%	3.55%	15.79%	22.01%	18.73%
10	9.12%	13.74%	11.21%	9.59%	18.59%	13.64%
11	9.68%	15.49%	12.50%	15.03%	44.30%	29.27%
12	8.46%	12.86%	10.53%	10.73%	24.59%	17.25%
Total	7.89%	10.85%	9.29%	13.11%	23.31%	17.94%

2006	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.93%	3.50%	2.66%	11.87%	25.12%	18.08%
2	1.94%	2.56%	2.24%	11.66%	20.64%	15.97%
3	9.04%	13.91%	11.41%	9.15%	14.12%	11.57%
4	8.26%	13.93%	10.77%	9.39%	14.26%	11.54%
5	2.27%	3.33%	2.80%	13.05%	16.67%	14.84%
6	2.44%	2.44%	2.44%	9.73%	10.69%	10.21%
7	2.89%	2.99%	2.94%	11.65%	13.07%	12.30%
8	2.57%	2.50%	2.53%	11.65%	11.10%	11.37%
9	2.28%	1.28%	1.83%	16.15%	23.60%	19.55%
10	1.39%	2.29%	1.82%	8.89%	22.12%	15.16%
11	1.95%	2.96%	2.44%	10.85%	24.56%	17.57%
12	10.13%	13.55%	11.67%	10.38%	14.45%	12.22%
Total	3.88%	5.17%	4.49%	11.23%	17.29%	14.12%

WUMS Base Case PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	14.93%	18.96%	16.91%	22.75%	50.90%	36.66%
2	11.53%	15.99%	13.66%	15.06%	23.85%	19.25%
3	9.97%	15.17%	12.41%	13.09%	21.03%	16.82%
4	8.47%	14.37%	11.20%	11.27%	23.21%	16.79%
5	7.34%	9.45%	8.39%	15.23%	18.46%	16.84%
6	8.32%	6.38%	7.39%	10.99%	9.47%	10.26%
7	9.31%	7.70%	8.53%	13.07%	11.95%	12.53%
8	8.18%	7.48%	7.83%	11.12%	11.12%	11.12%
9	11.96%	16.16%	13.78%	16.75%	24.81%	20.23%
10	10.83%	17.64%	14.19%	14.17%	30.22%	22.09%
11	11.91%	15.80%	13.82%	18.58%	37.64%	27.94%
12	10.48%	13.97%	12.06%	14.36%	26.42%	19.82%
Total	10.23%	12.95%	11.53%	14.64%	23.67%	18.97%

WUMS Contracts Scenario, PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	10.39%	20.55%	15.36%	14.15%	33.06%	23.40%
2	10.00%	19.97%	14.70%	14.01%	30.53%	21.79%
3	12.10%	20.90%	16.30%	15.35%	31.42%	23.02%
4	11.53%	20.01%	15.56%	15.40%	27.94%	21.36%
5	9.15%	17.33%	13.16%	12.46%	23.12%	17.68%
6	11.37%	21.75%	16.39%	15.25%	35.63%	25.11%
7	13.54%	21.45%	17.43%	17.88%	40.04%	28.78%
8	11.70%	18.49%	15.15%	14.82%	32.50%	23.81%
9	11.04%	20.93%	15.56%	13.40%	25.78%	19.06%
10	11.84%	23.38%	17.66%	13.62%	29.67%	21.71%
11	8.79%	18.22%	13.40%	10.71%	26.93%	18.65%
12	8.16%	15.11%	11.29%	8.86%	19.55%	13.68%
Total	10.82%	19.86%	15.19%	13.86%	30.04%	21.68%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	10.60%	22.91%	16.73%	14.10%	37.25%	25.63%
2	8.96%	20.94%	14.57%	12.74%	33.42%	22.43%
3	6.52%	14.20%	9.95%	9.43%	25.28%	16.50%
4	6.19%	13.55%	9.76%	7.48%	23.36%	15.18%
5	8.20%	15.86%	11.94%	10.89%	22.19%	16.41%
6	10.30%	18.62%	14.16%	13.07%	31.18%	21.48%
7	12.95%	20.28%	16.69%	16.52%	35.70%	26.31%
8	11.43%	19.98%	15.63%	15.02%	32.98%	23.83%
9	6.64%	16.45%	11.24%	8.64%	22.47%	15.12%
10	7.14%	18.17%	12.67%	8.85%	28.30%	18.59%
11	8.96%	21.65%	14.88%	11.14%	31.06%	20.44%
12	8.06%	18.14%	12.84%	10.14%	28.76%	18.97%
Total	8.91%	18.52%	13.54%	11.61%	29.61%	20.27%

WUMS Contracts Scenario, PCMI 2003-2004						
2003	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	11.15%	25.35%	18.10%	12.59%	33.42%	22.79%
2	11.29%	22.70%	16.72%	15.45%	33.76%	24.17%
3	7.23%	14.75%	10.60%	9.12%	19.62%	13.83%
4	6.71%	14.68%	10.58%	7.93%	18.35%	13.00%
5	8.33%	14.70%	11.36%	10.52%	19.71%	14.89%
6	8.03%	12.88%	10.36%	9.09%	18.61%	13.67%
7	10.14%	13.22%	11.68%	11.22%	20.51%	15.88%
8	8.80%	11.64%	10.12%	10.09%	18.10%	13.81%
9	5.83%	11.73%	8.73%	7.03%	14.00%	10.46%
10	6.92%	12.27%	9.62%	7.04%	18.56%	12.85%
11	7.35%	14.58%	10.57%	8.64%	19.52%	13.48%
12	6.03%	11.41%	8.70%	6.83%	15.83%	11.29%
Total	8.17%	14.89%	11.40%	9.63%	20.76%	14.98%

2004	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	13.72%	12.84%	13.29%	41.23%	76.04%	57.89%
2	11.88%	13.89%	12.82%	22.62%	54.50%	37.51%
3	11.05%	8.48%	9.78%	21.57%	45.65%	33.50%
4	10.76%	9.86%	10.33%	15.59%	49.95%	32.24%
5	12.27%	11.64%	11.99%	16.88%	30.39%	23.04%
6	12.88%	13.03%	12.96%	19.04%	38.37%	28.86%
7	13.54%	14.54%	14.03%	21.94%	44.88%	33.24%
8	12.73%	10.56%	11.65%	19.16%	36.35%	27.69%
9	11.04%	10.16%	10.61%	24.55%	55.73%	39.84%
10	11.47%	10.81%	11.17%	23.88%	58.10%	39.39%
11	11.96%	13.21%	12.57%	21.30%	53.44%	37.15%
12	11.30%	12.07%	11.68%	20.32%	47.85%	33.95%
Total	12.09%	11.80%	11.95%	22.39%	49.00%	35.29%

WUMS Contracts Scenario, PCMI 2005-2006						
2005	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.90%	8.73%	7.17%	6.72%	10.24%	8.30%
2	4.73%	10.29%	7.35%	5.89%	12.48%	8.99%
3	4.39%	9.12%	6.69%	3.87%	9.71%	6.71%
4	4.16%	8.79%	6.30%	3.12%	8.23%	5.48%
5	3.62%	5.24%	4.39%	5.27%	11.09%	8.02%
6	4.02%	4.25%	4.14%	5.43%	5.74%	5.59%
7	4.61%	5.00%	4.79%	5.90%	7.36%	6.56%
8	4.04%	5.37%	4.70%	5.17%	8.16%	6.67%
9	2.38%	2.76%	2.56%	2.95%	5.23%	4.03%
10	4.80%	9.92%	7.11%	4.29%	10.34%	7.02%
11	5.26%	10.33%	7.73%	5.90%	12.02%	8.88%
12	4.31%	8.54%	6.30%	4.80%	10.30%	7.39%
Total	4.36%	7.20%	5.70%	4.98%	9.13%	6.94%

2006	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.44%	2.58%	1.97%	4.03%	7.48%	5.64%
2	1.39%	1.88%	1.63%	3.03%	4.38%	3.68%
3	4.88%	9.55%	7.15%	3.79%	7.96%	5.82%
4	4.59%	9.57%	6.78%	3.01%	8.54%	5.45%
5	1.86%	2.63%	2.24%	3.56%	8.44%	5.97%
6	1.90%	1.81%	1.86%	3.31%	4.37%	3.84%
7	2.15%	2.18%	2.16%	4.18%	5.04%	4.57%
8	2.05%	1.84%	1.94%	2.88%	6.23%	4.57%
9	2.12%	1.02%	1.62%	2.98%	5.35%	4.06%
10	1.11%	1.75%	1.41%	2.79%	4.99%	3.83%
11	1.37%	2.17%	1.76%	3.29%	6.88%	5.05%
12	5.33%	8.90%	6.94%	3.80%	7.36%	5.40%
Total	2.50%	3.65%	3.05%	3.40%	6.37%	4.82%

WUMS Contracts Scenario, PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	7.81%	10.75%	9.26%	8.53%	11.62%	10.05%
2	6.25%	10.50%	8.28%	7.91%	11.43%	9.59%
3	5.17%	9.69%	7.29%	6.45%	10.12%	8.17%
4	4.44%	9.99%	7.01%	6.05%	11.39%	8.52%
5	4.30%	6.37%	5.33%	5.39%	9.36%	7.36%
6	5.11%	4.50%	4.82%	6.13%	6.38%	6.25%
7	5.64%	5.32%	5.49%	6.71%	6.55%	6.63%
8	4.67%	5.09%	4.88%	5.01%	7.32%	6.18%
9	6.49%	9.60%	7.83%	7.06%	11.88%	9.15%
10	5.79%	11.90%	8.81%	6.81%	12.35%	9.54%
11	6.82%	10.45%	8.61%	7.22%	11.92%	9.53%
12	5.55%	9.02%	7.12%	6.39%	10.36%	8.19%
Total	5.66%	8.41%	6.97%	6.62%	9.88%	8.18%

WUMS Divestiture Scenario, PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.80%	5.40%	3.56%	2.20%	9.91%	5.97%
2	1.67%	5.13%	3.30%	1.96%	8.90%	5.23%
3	4.49%	2.75%	3.66%	5.59%	9.53%	7.47%
4	4.59%	4.31%	4.45%	5.08%	8.21%	6.56%
5	1.68%	4.54%	3.08%	1.94%	7.51%	4.67%
6	2.12%	3.75%	2.91%	2.66%	9.03%	5.74%
7	2.90%	3.25%	3.07%	5.00%	10.77%	7.84%
8	2.43%	2.97%	2.71%	3.87%	10.24%	7.10%
9	4.16%	5.13%	4.60%	4.58%	10.13%	7.12%
10	3.01%	6.08%	4.56%	2.82%	10.19%	6.53%
11	1.91%	4.47%	3.16%	2.26%	9.41%	5.76%
12	2.50%	3.90%	3.13%	2.75%	5.72%	4.09%
Total	2.75%	4.27%	3.48%	3.40%	9.19%	6.19%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	2.45%	3.54%	2.98%	3.58%	6.45%	5.00%
2	1.69%	5.20%	3.34%	1.87%	10.09%	5.72%
3	1.90%	3.28%	2.51%	1.87%	5.27%	3.39%
4	2.70%	2.80%	2.75%	2.68%	4.11%	3.38%
5	1.57%	4.24%	2.88%	1.79%	7.54%	4.60%
6	2.30%	3.58%	2.89%	3.24%	8.53%	5.69%
7	2.95%	3.26%	3.11%	4.31%	10.72%	7.59%
8	2.63%	3.65%	3.13%	3.95%	10.75%	7.29%
9	1.92%	5.27%	3.49%	1.91%	9.03%	5.25%
10	1.80%	2.76%	2.28%	2.22%	5.23%	3.73%
11	2.08%	4.99%	3.44%	2.57%	8.91%	5.53%
12	2.12%	4.00%	3.01%	2.50%	6.68%	4.48%
Total	2.19%	3.84%	2.98%	2.74%	7.85%	5.20%

WUMS Divestiture Scenario, PCMI 2003-2004						
2003	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.66%	4.28%	2.93%	2.22%	6.54%	4.33%
2	1.81%	4.30%	2.99%	2.03%	6.30%	4.06%
3	1.78%	4.05%	2.80%	1.78%	7.06%	4.15%
4	1.97%	3.59%	2.76%	1.96%	6.45%	4.14%
5	1.93%	3.74%	2.79%	2.11%	6.99%	4.43%
6	2.24%	2.60%	2.41%	2.63%	6.23%	4.36%
7	2.55%	2.40%	2.47%	3.43%	6.66%	5.05%
8	2.58%	2.65%	2.61%	3.94%	6.65%	5.20%
9	1.74%	4.31%	3.00%	1.82%	6.59%	4.17%
10	2.07%	1.35%	1.71%	3.37%	3.54%	3.45%
11	2.28%	4.56%	3.29%	2.64%	6.81%	4.50%
12	2.15%	3.75%	2.94%	2.21%	5.86%	4.02%
Total	2.08%	3.39%	2.71%	2.55%	6.27%	4.33%

2004	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.61%	4.50%	2.95%	1.72%	7.77%	4.54%
2	2.19%	4.74%	3.36%	2.22%	8.05%	4.90%
3	2.44%	1.74%	2.10%	2.44%	1.74%	2.10%
4	2.97%	1.59%	2.30%	3.08%	1.67%	2.40%
5	1.33%	1.79%	1.53%	1.32%	3.64%	2.35%
6	2.01%	2.63%	2.32%	2.61%	3.92%	3.26%
7	1.98%	2.60%	2.28%	2.60%	3.75%	3.15%
8	1.87%	2.75%	2.29%	2.39%	4.00%	3.16%
9	1.16%	2.28%	1.70%	1.16%	2.85%	1.98%
10	2.33%	2.58%	2.45%	2.46%	4.60%	3.43%
11	2.15%	4.00%	3.05%	2.24%	5.98%	4.06%
12	2.23%	2.93%	2.57%	2.49%	3.80%	3.14%
Total	2.00%	2.83%	2.40%	2.22%	4.28%	3.20%

WUMS Divestiture Scenario, PCMI 2005-2006						
2005	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.91%	3.18%	2.48%	2.59%	4.58%	3.48%
2	1.76%	4.25%	2.93%	1.76%	4.78%	3.18%
3	2.05%	2.66%	2.35%	2.04%	2.99%	2.50%
4	2.32%	2.11%	2.22%	2.32%	2.13%	2.23%
5	1.26%	1.29%	1.27%	1.25%	2.45%	1.82%
6	1.46%	1.48%	1.47%	2.57%	2.86%	2.71%
7	2.08%	2.04%	2.06%	3.03%	4.18%	3.55%
8	1.79%	2.09%	1.94%	2.59%	5.27%	3.93%
9	1.18%	1.75%	1.45%	1.23%	3.00%	2.07%
10	1.85%	4.40%	3.00%	1.65%	7.23%	4.17%
11	1.92%	4.04%	2.95%	2.01%	5.91%	3.91%
12	1.90%	3.19%	2.51%	2.06%	3.71%	2.84%
Total	1.79%	2.65%	2.19%	2.12%	4.08%	3.05%

2006	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.16%	-0.27%	0.48%	1.83%	3.70%	2.70%
2	2.13%	0.26%	1.23%	3.27%	2.52%	2.91%
3	2.94%	3.80%	3.36%	2.77%	4.31%	3.52%
4	2.24%	1.82%	2.05%	2.24%	1.88%	2.08%
5	2.27%	-0.18%	1.06%	3.79%	2.71%	3.25%
6	2.20%	-0.61%	0.79%	3.54%	1.40%	2.46%
7	3.08%	4.02%	3.50%	4.38%	6.48%	5.32%
8	0.22%	8.15%	4.06%	0.94%	9.57%	5.12%
9	2.21%	3.73%	2.90%	2.53%	5.20%	3.73%
10	1.38%	6.39%	3.67%	2.52%	9.98%	5.93%
11	2.15%	6.34%	4.15%	2.73%	9.72%	6.06%
12	2.21%	7.85%	4.65%	2.21%	8.39%	4.88%
Total	2.01%	3.37%	2.65%	2.74%	5.44%	4.01%

WUMS Divestiture Scenario, PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.95%	2.60%	2.27%	2.97%	3.92%	3.43%
2	1.65%	3.91%	2.73%	1.74%	5.13%	3.35%
3	1.24%	3.65%	2.37%	1.26%	5.63%	3.31%
4	1.61%	3.17%	2.33%	1.59%	6.50%	3.86%
5	1.37%	1.77%	1.57%	1.40%	4.46%	2.92%
6	1.68%	1.35%	1.52%	2.38%	2.61%	2.49%
7	1.78%	1.30%	1.55%	3.58%	3.18%	3.39%
8	1.80%	1.60%	1.70%	2.08%	3.77%	2.94%
9	1.98%	1.69%	1.85%	1.99%	3.23%	2.53%
10	2.11%	4.92%	3.50%	2.20%	5.69%	3.92%
11	2.04%	3.15%	2.58%	2.39%	4.08%	3.22%
12	1.90%	2.92%	2.36%	2.11%	5.00%	3.42%
Total	1.76%	2.60%	2.16%	2.17%	4.36%	3.22%

WUMS Contracts & Divestiture Scenario, PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.31%	3.82%	2.53%	1.33%	4.64%	2.94%
2	1.33%	3.65%	2.42%	1.37%	4.90%	3.03%
3	3.15%	1.85%	2.53%	3.15%	1.85%	2.53%
4	3.05%	2.77%	2.92%	3.06%	2.97%	3.02%
5	1.31%	3.25%	2.26%	1.31%	3.86%	2.56%
6	1.55%	2.65%	2.08%	1.65%	4.13%	2.85%
7	1.95%	2.13%	2.04%	2.37%	3.57%	2.96%
8	1.65%	1.94%	1.79%	1.89%	3.84%	2.88%
9	2.87%	3.26%	3.05%	2.87%	3.42%	3.12%
10	1.48%	4.07%	2.79%	1.49%	4.66%	3.09%
11	1.39%	3.21%	2.28%	1.39%	3.84%	2.59%
12	1.95%	2.89%	2.37%	1.96%	3.48%	2.64%
Total	1.90%	2.93%	2.40%	1.98%	3.78%	2.85%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.62%	2.35%	1.97%	1.77%	2.98%	2.36%
2	1.28%	3.63%	2.38%	1.30%	4.65%	2.87%
3	1.55%	2.19%	1.84%	1.55%	2.31%	1.89%
4	2.23%	1.93%	2.08%	2.23%	1.95%	2.10%
5	1.22%	2.86%	2.02%	1.22%	3.55%	2.36%
6	1.63%	2.45%	2.01%	1.77%	4.23%	2.91%
7	1.88%	2.09%	1.99%	2.23%	3.65%	2.96%
8	1.69%	2.39%	2.03%	1.91%	4.09%	2.98%
9	1.52%	3.84%	2.61%	1.53%	4.79%	3.05%
10	1.19%	1.87%	1.53%	1.30%	3.21%	2.26%
11	1.51%	3.47%	2.42%	1.53%	4.83%	3.07%
12	1.46%	2.75%	2.07%	1.54%	3.34%	2.40%
Total	1.57%	2.62%	2.07%	1.66%	3.63%	2.61%

WUMS Contracts & Divestiture Scenario, PCMI 2003-2004						
2003	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.04%	2.81%	1.90%	1.09%	4.06%	2.54%
2	1.40%	2.91%	2.12%	1.47%	4.62%	2.97%
3	1.35%	2.53%	1.88%	1.35%	3.44%	2.29%
4	1.44%	2.33%	1.87%	1.45%	2.99%	2.20%
5	1.41%	2.50%	1.93%	1.45%	3.55%	2.45%
6	1.50%	1.74%	1.61%	1.62%	2.94%	2.25%
7	1.59%	1.55%	1.57%	2.01%	3.17%	2.59%
8	1.61%	1.72%	1.66%	1.89%	2.50%	2.18%
9	1.28%	2.83%	2.04%	1.29%	4.29%	2.76%
10	1.34%	0.95%	1.14%	1.54%	1.84%	1.69%
11	1.63%	3.21%	2.33%	1.73%	4.84%	3.12%
12	1.43%	2.49%	1.95%	1.48%	3.22%	2.34%
Total	1.42%	2.25%	1.82%	1.54%	3.41%	2.44%

2004	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.27%	3.21%	2.17%	1.28%	4.00%	2.55%
2	1.65%	3.08%	2.31%	1.67%	4.21%	2.83%
3	1.73%	1.16%	1.45%	1.72%	1.22%	1.48%
4	2.26%	0.92%	1.61%	2.26%	0.96%	1.62%
5	1.02%	2.33%	1.62%	1.02%	2.60%	1.74%
6	1.67%	1.97%	1.82%	1.73%	2.70%	2.22%
7	1.55%	1.72%	1.63%	1.81%	2.94%	2.37%
8	1.25%	1.76%	1.50%	1.32%	2.96%	2.13%
9	0.84%	1.38%	1.10%	0.84%	1.42%	1.12%
10	1.87%	1.82%	1.85%	1.87%	2.06%	1.95%
11	1.65%	2.76%	2.19%	1.67%	3.43%	2.53%
12	1.76%	2.12%	1.93%	1.76%	2.29%	2.02%
Total	1.53%	2.00%	1.76%	1.57%	2.58%	2.05%

2005	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.32%	2.32%	1.76%	1.45%	2.69%	2.00%
2	1.44%	3.18%	2.26%	1.44%	3.86%	2.58%
3	1.75%	1.77%	1.76%	1.74%	1.96%	1.84%
4	1.88%	1.47%	1.69%	1.79%	1.43%	1.62%
5	1.12%	0.86%	1.00%	1.12%	1.10%	1.11%
6	1.17%	1.22%	1.20%	1.36%	2.25%	1.80%
7	1.81%	1.75%	1.78%	2.04%	2.11%	2.08%
8	1.53%	1.88%	1.71%	1.61%	2.46%	2.04%
9	0.92%	1.64%	1.26%	0.92%	1.69%	1.29%
10	1.27%	3.04%	2.07%	1.15%	3.33%	2.13%
11	1.48%	3.03%	2.24%	1.53%	3.76%	2.61%
12	1.43%	2.33%	1.86%	1.44%	2.69%	2.03%
Total	1.43%	2.01%	1.70%	1.47%	2.42%	1.92%

2006	Strategic Bidding			Capacity Withholding and Strategic Bidding		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	0.58%	1.25%	0.89%	0.58%	1.69%	1.09%
2	0.64%	1.01%	0.81%	0.68%	1.61%	1.13%
3	1.33%	3.03%	2.16%	1.30%	3.24%	2.24%
4	1.69%	1.67%	1.68%	1.67%	1.74%	1.70%
5	1.14%	1.65%	1.39%	1.21%	2.16%	1.68%
6	1.11%	0.96%	1.04%	1.37%	1.55%	1.46%
7	1.30%	1.07%	1.20%	1.57%	1.54%	1.55%
8	1.29%	1.27%	1.28%	1.33%	1.80%	1.57%
9	1.12%	0.95%	1.05%	1.22%	1.02%	1.12%
10	0.69%	1.10%	0.89%	0.69%	1.71%	1.18%
11	0.76%	0.97%	0.86%	0.77%	1.49%	1.13%
12	1.59%	2.53%	2.01%	1.61%	2.82%	2.16%
Total	1.11%	1.44%	1.26%	1.18%	1.86%	1.50%

WUMS Contracts & Divestiture Scenario, PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	1.34%	1.84%	1.58%	1.47%	2.25%	1.85%
2	1.29%	2.74%	1.98%	1.31%	3.10%	2.16%
3	0.96%	2.52%	1.70%	0.97%	3.15%	1.99%
4	1.19%	2.33%	1.72%	1.20%	2.70%	1.89%
5	1.14%	1.53%	1.33%	1.16%	1.76%	1.46%
6	1.44%	1.07%	1.26%	1.60%	1.52%	1.56%
7	1.49%	1.01%	1.26%	1.56%	1.22%	1.40%
8	1.50%	1.27%	1.38%	1.62%	1.83%	1.73%
9	1.68%	1.28%	1.51%	1.70%	1.32%	1.53%
10	1.71%	3.48%	2.58%	1.71%	4.10%	2.89%
11	1.51%	2.27%	1.88%	1.54%	2.88%	2.20%
12	1.39%	2.06%	1.70%	1.43%	2.26%	1.80%
Total	1.39%	1.91%	1.64%	1.45%	2.30%	1.85%

MAPP Base Case, PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.06%	7.10%	6.03%	6.31%	10.61%	8.36%
2	5.37%	5.76%	5.55%	6.36%	8.29%	7.26%
3	5.62%	4.11%	4.92%	6.60%	4.64%	5.68%
4	5.83%	3.64%	4.81%	7.83%	4.67%	6.36%
5	5.29%	4.29%	4.80%	6.18%	5.36%	5.78%
6	5.56%	6.11%	5.82%	6.67%	8.23%	7.40%
7	5.43%	6.67%	6.01%	6.37%	8.93%	7.57%
8	5.38%	6.69%	6.02%	6.39%	9.28%	7.80%
9	4.94%	5.65%	5.25%	6.04%	6.97%	6.45%
10	5.42%	5.00%	5.21%	6.01%	5.49%	5.76%
11	5.23%	6.16%	5.67%	6.09%	8.97%	7.47%
12	5.24%	6.01%	5.58%	6.54%	8.73%	7.51%
Total	5.36%	5.62%	5.48%	6.45%	7.54%	6.96%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.77%	7.57%	6.63%	7.22%	11.79%	9.42%
2	5.86%	5.22%	5.56%	6.85%	7.81%	7.30%
3	5.37%	4.14%	4.82%	7.01%	4.59%	5.92%
4	4.76%	3.99%	4.39%	7.29%	4.73%	6.04%
5	5.82%	4.71%	5.28%	6.64%	6.01%	6.33%
6	6.03%	6.28%	6.14%	7.17%	8.75%	7.88%
7	6.24%	6.53%	6.38%	7.18%	9.31%	8.23%
8	6.03%	6.48%	6.24%	6.95%	9.32%	8.07%
9	5.12%	5.44%	5.27%	6.23%	7.43%	6.79%
10	5.32%	5.84%	5.58%	6.25%	9.75%	7.97%
11	5.04%	6.27%	5.61%	6.19%	9.99%	7.94%
12	4.96%	5.75%	5.33%	6.90%	9.27%	8.01%
Total	5.54%	5.71%	5.62%	6.83%	8.28%	7.52%

MAPP Base Case, PCMI 2003-2004						
2003	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	6.38%	7.95%	7.13%	7.14%	9.84%	8.44%
2	6.36%	7.02%	6.67%	7.05%	10.08%	8.46%
3	7.14%	6.03%	6.64%	7.60%	7.69%	7.64%
4	6.90%	5.45%	6.19%	8.23%	6.48%	7.38%
5	6.78%	5.78%	6.31%	7.00%	7.38%	7.18%
6	6.99%	5.80%	6.43%	7.38%	6.82%	7.12%
7	7.19%	5.79%	6.50%	9.80%	6.03%	7.93%
8	6.68%	5.96%	6.35%	10.72%	2.89%	7.17%
9	6.24%	7.20%	6.71%	9.94%	5.37%	7.71%
10	5.97%	6.67%	6.31%	9.41%	5.56%	7.53%
11	6.02%	7.52%	6.67%	11.52%	7.43%	9.73%
12	5.91%	6.80%	6.35%	9.81%	5.17%	7.44%
Total	6.55%	6.49%	6.52%	8.83%	6.73%	7.82%

2004	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.59%	7.00%	6.24%	6.59%	10.72%	8.49%
2	5.91%	6.32%	6.09%	6.39%	8.99%	7.57%
3	6.28%	4.80%	5.56%	6.91%	7.13%	7.01%
4	6.32%	4.21%	5.29%	7.94%	5.97%	6.98%
5	4.68%	5.45%	5.02%	4.90%	7.78%	6.18%
6	6.16%	5.41%	5.79%	6.72%	7.38%	7.04%
7	6.12%	5.46%	5.81%	7.11%	7.38%	7.24%
8	5.48%	5.74%	5.60%	6.17%	7.63%	6.86%
9	5.38%	5.81%	5.59%	5.46%	8.90%	7.13%
10	5.80%	5.88%	5.83%	5.99%	9.04%	7.36%
11	5.69%	6.73%	6.19%	6.53%	10.25%	8.32%
12	5.54%	6.32%	5.92%	6.46%	9.49%	7.94%
Total	5.74%	5.76%	5.75%	6.42%	8.37%	7.34%

MAPP Base Case, PCMI 2005-2006						
2005	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.26%	6.01%	5.59%	7.03%	8.39%	7.62%
2	5.87%	6.52%	6.18%	6.46%	8.78%	7.55%
3	6.01%	5.86%	5.94%	6.50%	7.89%	7.18%
4	6.41%	5.36%	5.92%	7.25%	7.56%	7.39%
5	5.48%	5.72%	5.60%	5.78%	7.69%	6.67%
6	5.80%	5.56%	5.68%	6.28%	7.23%	6.75%
7	6.06%	5.60%	5.85%	6.98%	7.24%	7.10%
8	5.60%	5.84%	5.72%	6.28%	7.61%	6.94%
9	5.30%	6.05%	5.66%	5.55%	8.38%	6.90%
10	5.47%	6.67%	6.00%	5.75%	8.68%	7.06%
11	5.60%	6.21%	5.89%	6.48%	8.82%	7.61%
12	5.68%	6.28%	5.96%	6.80%	9.70%	8.16%
Total	5.71%	5.96%	5.83%	6.44%	8.15%	7.24%

2006	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	4.49%	8.60%	6.36%	7.42%	13.03%	9.97%
2	4.14%	8.34%	6.06%	6.12%	12.96%	9.26%
3	5.10%	6.35%	5.70%	5.88%	11.50%	8.59%
4	5.29%	5.47%	5.37%	5.52%	9.08%	7.08%
5	4.73%	6.42%	5.54%	5.61%	10.61%	8.03%
6	4.92%	5.29%	5.10%	5.64%	6.63%	6.12%
7	5.53%	5.61%	5.57%	7.09%	6.49%	6.82%
8	5.02%	6.14%	5.57%	6.20%	7.95%	7.06%
9	4.89%	6.15%	5.46%	5.68%	9.77%	7.53%
10	4.93%	7.56%	6.15%	6.14%	12.75%	9.20%
11	4.87%	7.76%	6.25%	6.93%	11.75%	9.23%
12	5.33%	7.15%	6.14%	6.56%	12.01%	8.98%
Total	4.95%	6.72%	5.77%	6.25%	10.31%	8.14%

MAPP Base Case, PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	5.80%	6.77%	6.27%	8.32%	8.81%	8.55%
2	4.71%	8.63%	6.52%	7.25%	13.13%	9.97%
3	5.31%	7.93%	6.52%	6.71%	13.18%	9.69%
4	5.11%	6.77%	5.87%	6.34%	11.90%	8.89%
5	5.18%	7.14%	6.13%	6.42%	11.22%	8.75%
6	5.70%	4.92%	5.33%	6.87%	6.37%	6.63%
7	6.06%	4.96%	5.54%	7.43%	5.93%	6.71%
8	5.69%	5.62%	5.66%	7.38%	7.38%	7.38%
9	5.41%	8.15%	6.59%	7.11%	12.53%	9.44%
10	5.61%	8.93%	7.22%	7.59%	12.64%	10.04%
11	5.37%	7.27%	6.28%	7.59%	10.08%	8.79%
12	5.82%	7.77%	6.68%	7.60%	11.82%	9.48%
Total	5.49%	7.01%	6.21%	7.22%	10.27%	8.65%

MAPP Contracts & Divestiture Scenario, PCMI 2001-2002						
2001	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	3.21%	4.79%	3.96%	3.46%	7.62%	5.45%
2	3.61%	3.39%	3.51%	3.73%	6.15%	4.85%
3	3.59%	1.97%	2.83%	4.04%	2.27%	3.21%
4	3.89%	1.84%	2.93%	5.52%	2.23%	3.98%
5	3.37%	2.30%	2.85%	3.56%	2.77%	3.18%
6	3.58%	4.31%	3.92%	3.97%	6.13%	4.97%
7	3.35%	4.83%	4.05%	3.61%	7.28%	5.33%
8	3.27%	4.80%	4.02%	3.61%	7.01%	5.28%
9	2.90%	3.30%	3.08%	3.05%	4.66%	3.76%
10	3.43%	2.61%	3.03%	3.61%	3.12%	3.37%
11	3.24%	3.87%	3.54%	3.33%	6.04%	4.63%
12	3.19%	3.84%	3.48%	3.93%	6.01%	4.85%
Total	3.38%	3.51%	3.44%	3.78%	5.14%	4.42%

2002	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	4.21%	6.17%	5.15%	5.39%	10.63%	7.91%
2	4.40%	3.78%	4.11%	5.21%	7.33%	6.20%
3	3.83%	2.83%	3.38%	5.39%	3.72%	4.63%
4	3.28%	2.76%	3.02%	5.84%	3.96%	4.92%
5	4.25%	3.30%	3.78%	5.07%	5.37%	5.21%
6	4.45%	5.15%	4.77%	5.68%	8.16%	6.79%
7	4.53%	5.40%	4.96%	5.57%	8.18%	6.86%
8	4.31%	5.20%	4.74%	5.03%	8.19%	6.53%
9	3.58%	4.00%	3.78%	4.32%	6.77%	5.46%
10	3.70%	4.38%	4.04%	4.29%	8.58%	6.39%
11	3.60%	4.91%	4.20%	4.44%	9.13%	6.60%
12	3.43%	4.29%	3.83%	5.07%	8.41%	6.63%
Total	3.97%	4.38%	4.16%	5.11%	7.41%	6.20%

MAPP Contracts & Divestiture Scenario, PCMI 2003-2004						
2003	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	3.45%	5.33%	4.35%	4.22%	9.42%	6.73%
2	3.65%	4.35%	3.98%	3.73%	7.27%	5.38%
3	3.86%	2.80%	3.38%	4.45%	5.10%	4.74%
4	3.55%	2.37%	2.97%	5.35%	3.86%	4.62%
5	3.73%	2.73%	3.26%	3.84%	4.63%	4.21%
6	4.02%	3.61%	3.83%	4.53%	5.36%	4.92%
7	4.05%	3.73%	3.89%	4.82%	5.45%	5.13%
8	3.54%	3.73%	3.63%	4.18%	5.61%	4.83%
9	3.11%	4.13%	3.61%	3.28%	7.17%	5.18%
10	3.35%	3.92%	3.63%	3.46%	7.37%	5.37%
11	3.33%	4.86%	4.00%	3.76%	8.33%	5.76%
12	3.17%	4.24%	3.69%	4.04%	7.52%	5.74%
Total	3.57%	3.82%	3.69%	4.14%	6.43%	5.22%

2004	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	3.44%	5.06%	4.18%	4.33%	8.90%	6.43%
2	4.06%	5.20%	4.58%	4.49%	8.19%	6.16%
3	3.65%	3.31%	3.48%	3.82%	5.96%	4.86%
4	4.53%	2.91%	3.74%	5.44%	5.05%	5.25%
5	2.85%	3.74%	3.25%	2.97%	6.08%	4.35%
6	4.31%	4.17%	4.24%	4.70%	5.90%	5.29%
7	4.19%	4.18%	4.19%	5.07%	5.90%	5.46%
8	3.39%	4.22%	3.78%	3.79%	6.15%	4.91%
9	3.26%	4.07%	3.66%	3.26%	7.06%	5.11%
10	3.42%	4.41%	3.87%	3.55%	7.33%	5.24%
11	3.48%	5.03%	4.22%	4.11%	8.79%	6.36%
12	3.67%	4.55%	4.10%	4.48%	7.72%	6.06%
Total	3.68%	4.23%	3.94%	4.16%	6.90%	5.46%

MAPP Contracts & Divestiture Scenario, PCMI 2005-2006						
2005	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	3.46%	4.28%	3.82%	4.90%	7.71%	6.14%
2	3.83%	4.66%	4.22%	4.19%	6.82%	5.42%
3	3.45%	4.35%	3.89%	3.70%	7.12%	5.36%
4	4.23%	3.98%	4.11%	4.46%	6.42%	5.37%
5	3.48%	3.82%	3.64%	3.60%	5.73%	4.60%
6	3.88%	4.11%	3.99%	4.15%	5.41%	4.77%
7	4.07%	4.26%	4.15%	4.90%	5.93%	5.36%
8	3.48%	4.33%	3.90%	4.00%	5.90%	4.94%
9	3.20%	4.03%	3.59%	3.26%	6.56%	4.84%
10	3.10%	4.84%	3.87%	3.27%	7.68%	5.24%
11	3.45%	4.25%	3.83%	4.42%	7.65%	5.97%
12	3.58%	4.48%	4.00%	4.07%	7.52%	5.68%
Total	3.60%	4.28%	3.92%	4.09%	6.69%	5.31%

2006	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	2.53%	6.01%	4.12%	5.50%	10.35%	7.72%
2	2.38%	6.14%	4.11%	4.53%	11.36%	7.67%
3	3.17%	4.80%	3.95%	3.85%	10.28%	6.93%
4	3.14%	3.81%	3.43%	3.52%	9.47%	6.11%
5	2.99%	4.24%	3.60%	3.56%	8.45%	5.92%
6	3.13%	3.70%	3.41%	3.97%	5.53%	4.74%
7	3.58%	4.25%	3.88%	5.01%	5.10%	5.05%
8	2.98%	4.53%	3.75%	4.34%	6.53%	5.42%
9	3.03%	3.54%	3.26%	3.66%	8.57%	5.88%
10	3.39%	6.27%	4.72%	4.68%	11.18%	7.69%
11	3.01%	5.52%	4.21%	5.06%	9.20%	7.04%
12	3.13%	5.10%	4.00%	4.53%	10.52%	7.17%
Total	3.05%	4.82%	3.87%	4.36%	8.80%	6.43%

MAPP Contracts & Divestiture Scenario, PCMI 2007						
2007	**Strategic Bidding**			**Capacity Withholding and Strategic Bidding**		
Month	Off-Peak	On-Peak	All hours	Off-Peak	On-Peak	All hours
1	4.01%	4.95%	4.46%	6.70%	6.22%	6.46%
2	3.24%	6.80%	4.89%	5.43%	10.90%	7.96%
3	3.30%	6.64%	4.83%	4.31%	12.37%	8.02%
4	3.50%	5.97%	4.63%	4.07%	12.03%	7.70%
5	3.27%	5.10%	4.16%	4.14%	9.82%	6.90%
6	3.71%	3.12%	3.43%	4.89%	4.77%	4.83%
7	4.04%	3.38%	3.72%	5.39%	4.57%	5.00%
8	3.52%	3.84%	3.68%	5.17%	6.01%	5.58%
9	3.31%	5.60%	4.30%	4.54%	10.90%	7.28%
10	3.85%	7.04%	5.40%	5.33%	10.78%	7.97%
11	3.76%	5.28%	4.50%	5.97%	7.60%	6.76%
12	3.55%	5.52%	4.43%	5.16%	9.94%	7.28%
Total	3.59%	5.22%	4.36%	5.09%	8.67%	6.78%

Appendix E. Rate Impact and Stranded Cost/Benefit Analysis Details

E.1 Rate Unbundling Details

The following tables detail the rate unbundling analyses. The data are based on 1998 electricity rates, and all dollar values are in 1998 dollars.

E.1.1 Unbundling Results: Wisconsin Electric Power

Category	Total	Components			
		Generation	Transmission	Distribution	Customer
Costs (thousand $)					
O&M Expenses:					
O&M Minus Fuel & A&G	$548,297	$395,841	$15,863	$64,031	$72,562
Fuel	$305,173	$305,173			
Subtotal	$853,470	$701,014	$15,863	$64,031	$72,562
A&G	$57,526	$ 41,531	$ 1,664	$ 6,718	$ 7,613
Pensions/Office Supplies	$89,160	$59,732	$2,538	$16,136	$10,755
Uncollectibles	$9,723	$6,563	$388	$2,205	$567
Total	$1,009,879	$808,839	$20,453	$89,090	$91,497
Plant Related Costs:					
Depreciation and Amort.	$215,668	$112,786	$16,464	$86,418	$0
Net Interest	$98,901	$39,627	$7,409	$51,865	$0
Net Income	$152,682	$61,176	$11,438	$80,069	$0
Income Taxes[1]	$95,488	$38,260	$7,153	$50,075	$0
Other Taxes	$71,695	$41,589	$3,731	$23,642	$2,733
Other Op Expenses	($2,911)	($1,166)	($218)	($1,527)	$0
Total	$631,524	$292,271	$45,977	$290,542	$2,733
Total Operating Revenues	$1,641,403	$1,101,110	$66,430	$379,631	$94,230
less Wholesale Revenues	($117,805)	($111,102)	($6,703)	$0	$0
Total Retail Revenues	$1,523,598	$990,009	$59,728	$379,631	$94,230
less State Sales Taxes	($47,611)	($31,939)	($1,927)	($11,012)	($2,733)
Adjusted Retail Revenues	$1,475,987	$958,070	$57,801	$368,620	$91,497
Total Retail Sales (MWH)	26,504,601				
Average unit net retail revenue (cents/kWh)					
System wide 2	**5.57**	**3.61**	**0.22**	**1.39**	**0.35**
residential 3,4	**7.43**	**3.61**	**3.81**		
commercial 3,4	**6.10**	**3.61**	**2.48**		
industrial 3,4	**3.76**	**3.61**	**0.15**		

Footnotes:

[1] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

2 Adjusted retail revenues divided by total retail sales

3 average unit net retail revenue by class equals annual retail revenues by class divided by annual sales

4 unit transmission, distribution and customer component by class equals average unit net retail revenue by class minus system average unit generation revenue component

E.1.2 Unbundling Results: Wisconsin Public Service

Category	Total	Components			
		Generation	Transmission	Distribution	Customer
Costs (thousand $)					
O&M Expenses:					
O&M Minus Fuel & A&G	$255,687	$202,931	$19,828	$19,119	$13,808
Fuel	$11,355	$11,355			
Subtotal	$267,042	$214,286	$19,828	$19,119	$13,808
A&G	$8,587	$ 6,815	$ 666	$ 642	$ 464
Pensions/Office Supplies	$10,090	$3,258	$779	$3,774	$2,279
Uncollectibles	$1,225	$817	$148	$207	$53
Total	$286,944	$225,176	$21,421	$23,742	$16,604
Plant Related Costs:					
Depreciation and Amort.	$33,377	$11,749	$8,050	$13,578	$0
Net Interest	$15,972	$4,907	$4,215	$6,851	$0
Net Income	$29,828	$9,164	$7,870	$12,793	$0
Income Taxes1	$19,946	$6,128	$5,263	$8,555	$0
Other Taxes	$12,943	$7,255	$2,112	$3,183	$393
Other Op Expenses	($799)	($245)	($211)	($343)	$0
Total	$111,267	$38,958	$27,299	$44,617	$393
Total Operating Revenues	$398,211	$264,134	$48,720	$68,359	$16,997
less Wholesale Revenues	($92,897)	($78,430)	($14,467)	$0	$0
Total Retail Revenues	$305,314	$185,703	$34,253	$68,359	$16,997
less State Sales Taxes	($9,207)	($6,107)	($1,126)	($1,580)	($393)
Adjusted Retail Revenues	$296,107	$179,597	$33,127	$66,779	$16,604
Total Retail Sales (MWH)	5,380,329				
Average unit net retail revenue (cents/kWh)					
System wide 2	**5.50**	**3.34**	**0.62**	**1.24**	**0.31**
residential 3,4	**6.76**	**3.34**	**3.42**		
commercial 3,4	**6.30**	**3.34**	**2.97**		
industrial 3,4	**4.48**	**3.34**	**1.14**		

Footnotes:

[1] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

2 Adjusted retail revenues divided by total retail sales

3 average unit net retail revenue by class equals annual retail revenues by class divided by annual sales

4 unit transmission, distribution and customer component by class equals average unit net retail revenue by class minus system average unit generation revenue component

E.1.3 Unbundling Results: Wisconsin Power & Light

Category	Total	Generation	Transmission	Distribution	Customer
		Components			
Costs (thousand $)					
O&M Expenses:					
O&M Minus Fuel & A&G	$227,759	$164,488	$24,568	$21,048	$17,654
Fuel	$113,461	$113,461			
Subtotal	$341,220	$277,949	$24,568	$21,048	$17,654
A&G	$26,490	$ 19,131	$ 2,857	$ 2,448	$ 2,053
Pensions/Office Supplies	$24,084	$13,048	$1,197	$5,773	$4,066
Uncollectibles	$1,530	$993	$160	$315	$62
Total	$393,324	$311,121	$28,783	$29,583	$23,835
Plant Related Costs:					
Depreciation and Amort.	$104,456	$47,897	$15,923	$40,635	$0
Net Interest	$31,889	$8,079	$5,979	$17,831	$0
Net Income	$35,324	$8,950	$6,623	$19,751	$0
Income Taxes[1]	$25,485	$6,457	$4,778	$14,250	$0
Other Taxes	$24,234	$11,382	$3,449	$8,866	$536
Other Op Expenses	($1,800)	($456)	($337)	($1,006)	$0
Total	$219,586	$82,309	$36,415	$100,326	$536
Total Operating Revenues	$612,910	$393,430	$65,198	$129,909	$24,371
less Wholesale Revenues	($147,772)	($126,765)	($21,007)	$0	$0
Total Retail Revenues	$465,138	$266,665	$44,191	$129,909	$24,371
less State Sales Taxes	($13,492)	($8,661)	($1,435)	($2,860)	($536)
Adjusted Retail Revenues	$451,646	$258,004	$42,756	$127,050	$23,835
Total Retail Sales (MWH)	9,200,680				
Average unit net retail revenue (cents/kWh)					
System wide 2	**4.91**	**2.80**	**0.46**	**1.38**	**0.26**
residential 3,4	**6.40**	**2.80**	**3.60**		
commercial 3,4	**5.46**	**2.80**	**2.66**		
industrial 3,4	**3.45**	**2.80**	**0.65**		

Footnotes:

[1] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

2 Adjusted retail revenues divided by total retail sales

3 average unit net retail revenue by class equals annual retail revenues by class divided by annual sales

4 unit transmission, distribution and customer component by class equals average unit net retail revenue by class minus system average unit generation revenue component

E.1.4 Unbundling Results: Northern States Power (WI)

Category	Total	Components			
		Generation	Transmission	Distribution	Customer
Costs (thousand $)					
O&M Expenses:					
O&M Minus Fuel & A&G	$255,687	$202,931	$19,828	$19,119	$13,808
Fuel	$11,355	$11,355			
Subtotal	$267,042	$214,286	$19,828	$19,119	$13,808
A&G	$8,587	$ 6,815	$ 666	$ 642	$ 464
Pensions/Office Supplies	$10,090	$3,258	$779	$3,774	$2,279
Uncollectibles	$1,225	$817	$148	$207	$53
Total	$286,944	$225,176	$21,421	$23,742	$16,604
Plant Related Costs:					
Depreciation and Amort.	$33,377	$11,749	$8,050	$13,578	$0
Net Interest	$15,972	$4,907	$4,215	$6,851	$0
Net Income	$29,828	$9,164	$7,870	$12,793	$0
Income Taxes1	$19,946	$6,128	$5,263	$8,555	$0
Other Taxes	$12,943	$7,255	$2,112	$3,183	$393
Other Op Expenses	($799)	($245)	($211)	($343)	$0
Total	$111,267	$38,958	$27,299	$44,617	$393
Total Operating Revenues	$398,211	$264,134	$48,720	$68,359	$16,997
less Wholesale Revenues	($92,897)	($78,430)	($14,467)	$0	$0
Total Retail Revenues	$305,314	$185,703	$34,253	$68,359	$16,997
less State Sales Taxes	($9,207)	($6,107)	($1,126)	($1,580)	($393)
Adjusted Retail Revenues	$296,107	$179,597	$33,127	$66,779	$16,604
Total Retail Sales (MWH)	5,380,329				
Average unit net retail revenue (cents/kWh)					
System wide 2	**5.50**	**3.34**	**0.62**	**1.24**	**0.31**
residential 3,4	**6.76**	**3.34**	**3.42**		
commercial 3,4	**6.30**	**3.34**	**2.97**		
industrial 3,4	**4.48**	**3.34**	**1.14**		

Footnotes:

[1] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

2 Adjusted retail revenues divided by total retail sales

3 average unit net retail revenue by class equals annual retail revenues by class divided by annual sales

4 unit transmission, distribution and customer component by class equals average unit net retail revenue by class minus system average unit generation revenue component

E.2 Net Book Value of Generating Plants of Wisconsin Utilities

E.2.1 Net Book Value of Wisconsin Electric Power Plants

Unit	Gross Plant Value	Accumulated Depreciation	Net Plant Value	Deferred Tax Balance	Net Plant Values Incl. Deferred Tax
Ash Disposal Sites	16,311,964	761,511	15,550,453		15,550,453
Commerce St.		(1,237,105)	1,237,105		1,237,105
Concord	107,522,170	18,955,641	88,566,529		88,566,529
Edgewater 5	74,100,636	29,968,841	44,131,795		44,131,795
Germantown	35,626,200	36,914,312	(1,288,112)		(1,288,112)
Menasha			-		-
Milwaukee County	773,719	155,630	618,089		618,089
Paris	107,220,435	13,796,180	93,424,255		93,424,255
Pleasant Prairie	728,759,688	326,496,172	402,263,516		402,263,516
P4 Unit Train	43,712,592	34,712,993	8,999,599		8,999,599
Presque Isle	276,615,494	93,994,073	182,621,421		182,621,421
Point Beach	1,064,534,471	811,262,697	253,271,774	10,539,951	263,811,725
Point Beach CT	1,718,479	1,907,272	(188,793)		(188,793)
Port Washington	120,740,013	85,228,421	35,511,592		35,511,592
Port Washington CT	2,005,414	2,323,195	(317,781)		(317,781)
South Oak Creek	385,964,574	206,942,669	179,021,905		179,021,905
South Oak Creek CT	2,229,115	2,181,896	47,219		47,219
South Oak Creek Unit Train	31,044,274	7,396,438	23,647,836		23,647,836
Valley	94,647,938	41,425,114	53,222,824		53,222,824
Wind Turbines - Eastern WI	1,588,917	75,123	1,513,794		1,513,794
Whitewater - Cogentrix Plant			127,326,667		127,326,667
Total Steam Deferred Taxes				(214,979,643)	(214,979,643)
Total Other Production Def. Tax				(9,781,712)	(9,781,712)
Total:					**1,294,960,283**

E.2.2 Net Book Value of Madison Gas and Electric Plants

Unit	Gross Plant Value	Accumulated Depreciation	Net Plant Value	Deferred Tax Balance	Net Plant Values Incl. Deferred Tax
Columbia	80,189,023	49,528,204	30,660,819	(11,307,882)	19,352,937
Nine Springs	1,595,386	1,684,229	(88,843)	(1,297)	(90,140)
Blount	53,044,538	38,765,268	14,279,270	(3,018,402)	11,260,868
Fitchburg	345,536	243,583	101,953	(9,986)	91,967
Kewaunee	120,941,507	108,979,606	11,961,901	4,416,385	16,378,286
Sycamore	1,938,054	1,848,441	89,613	(62,218)	27,395
MGE Diesels	4,688,141	62,155	4,625,986	(68,113)	4,557,873
Wisconsin Wind	13,386,074	151,233	13,234,841	(924,547)	12,310,294
Miscellaneous Other Generation	14,907	1,585	13,322	(2,413)	10,909
Total:					**63,900,389**

E.2.3 Net Book Value of Wisconsin Power & Light Plants

Unit	Gross Plant Value	Accumulated Depreciation	Net Plant Value	Deferred Tax Balance	Net Plant Values Incl. Deferred Tax
Blackhawk	10,862,560	11,441,470	(578,910)	464,230	(114,680)
Columbia	163,197,434	97,780,867	65,416,567	20,699,897)	44,716,670
Edgewqter	301,606,480	139,206,291	162,400,189	59,443,301)	102,956,888
Nelson Dewey	55,453,804	40,606,431	14,847,373	(1,734,436)	13,112,937
Kewaunee	296,715,447	264,712,974	32,002,473	6,376,584	38,379,057
South Fond Du Lac	1,677,380	8,952,283	(7,274,903)	(5,759,830)	(13,034,733)
Rock River	49,080,063	35,938,825	13,141,238	(343,104)	12,798,134
Rock River CT	14,004,389	14,153,629	(149,240)	154,446	5,206
Sheepskin	3,533,408	3,691,350	(157,942)	72,893	(85,049)
Portable Generator	421,164	212,600	208,564	14,084	222,648
Excess & Unfunded Steam Accum Def Tax				(3,206,766)	(3,206,766)
Excess & Unfunded Other Accum Def Tax				(869,673)	(869,673)
Total:					**194,880,639**

E.2.4 Net Book Value of Wisconsin Public Service Plants

Unit	Gross Plant Value	Accumulated Depreciation	Net Plant Value	Deferred Tax Balance	Net Plant Values Incl. Deferred Tax
Columbia			41,711,514	16,638,004)	25,073,510
DePere			72,507,191	621,899	73,129,090
Eagle River			35,866	364	36,230
Edgewater			8,563,451	(1,591,464)	6,971,987
Kewaunee			27,029,471	6,868,815	33,898,286
Oneida Diesel			978,215	(53,748)	924,467
Pulliam			69,819,421	14,219,230)	55,600,191
West Marinette			13,126,392	(1,409,284)	11,717,108
Weston			118,217,165	43,765,968)	74,451,197
Wind			9,980,881	(742,515)	9,238,366
Total:					**291,040,432**

E.3 Market Value of Generating Plants of Wisconsin Utilities under Perfect Competition

The following tables detail the market valuation of generating plants owned by Wisconsin utilities. All monetary values are in 1999 dollars unless otherwise noted.

E.3.1 Market Value of Wisconsin Electric Power Plants

Unit Name	% Ownership	Installation Date	Type	Capacity	Market Value ($Millions)	Market Value ($/Kw)
South Oak Creek 9	100%	12/1/1968	GTgo	18	3	150
Concord 3	100%	6/1/1994	GTgo	83	12	150
Concord 4	100%	6/1/1994	GTgo	83	12	150
Paris 3	100%	6/1/1995	GTgo	83	12	150
Paris 4	100%	6/1/1995	GTgo	83	12	150
Concord 1	100%	7/1/1993	GTgo	94	14	150
Concord 2	100%	7/1/1993	GTgo	94	14	150
Paris 1	100%	6/1/1995	GTgo	94	14	150
Paris 2	100%	6/1/1995	GTgo	94	14	150
Point Beach 5	100%	6/1/1969	GTo	16	2	150
Port Washington	100%	6/1/1969	GTo	18	3	150
Valley - Diesel	100%	1/1/1969	ICo	3	0	150
Point Beach 1	100%	12/1/1970	NU	505	121	239
Point Beach 2	100%	4/1/1973	NU	507	129	254
Menasha 2	100%	1/1/1964	STc	9	0	41
Menasha 1	100%	1/1/1964	STc	15	2	115
Port Washington 1	100%	1/1/1935	STc	80	23	287
Port Washington 2	100%	1/1/1943	STc	80	23	287
Port Washington 3	100%	1/1/1948	STc	83	24	287
Port Washington 4	100%	1/1/1949	STc	83	24	287
Valley 2	100%	3/1/1969	STc	127	25	198
Valley 1	100%	1/1/1968	STc	140	32	228
South Oak Creek 5	100%	1/1/1960	STc	261	242	928
South Oak Creek 6	100%	1/1/1961	STc	264	231	875
South Oak Creek 7	100%	1/1/1965	STc	298	257	862
South Oak Creek 8	100%	1/1/1967	STc	312	263	842
Edgewater 5	25%	3/1/1985	STc	402	78	781
Pleasant Prairie 1	100%	6/1/1980	STc	600	629	1,048
Pleasant Prairie 2	100%	7/1/1985	STc	600	628	1,047
Milwaukee County	100%	1/1/1996	STo	11	2	150
Total:					2,847	

E.3.2 Market Value of Madison Gas & Electric Plants

Unit Name	% Ownership	Installation Date	Type	Capacity	Market Value ($Millions)	Market Value ($/Kw)
Nine Springs	100%	1/1/1964	GTgk	13	2	150
Sycamore 1	100%	12/1/1967	GTgo	14	2	150
Fitchburg 2	100%	5/1/1973	GTgo	20	3	150
Fitchburg 1	100%	5/1/1973	GTgo	21	3	150
Sycamore 2	100%	6/1/1971	GTgo	21	3	150
MGE Diesels	100%	1/1/1999	ICo	13	2	150
Kewaunee	18%	6/1/1974	NU	498	21	242
Columbia 1	22%	5/1/1975	STc	525	82	712
Columbia 2	22%	4/1/1978	STc	525	82	711
Blount Street 1	100%	1/1/1925	STcg	6	2	395
Blount Street 4	100%	1/1/1938	STcg	22	9	395
Blount Street 5	100%	1/1/1948	STcg	28	11	395
Blount Street 3	100%	1/1/1953	STcg	40	16	388
Blount Street 6	100%	1/1/1957	STcg	50	19	388
Blount Street 7	100%	1/1/1961	STcg	50	19	388
Wisconsin Wind	100%	1/1/1999	WND	9	-	
Total:					277	

E.3.3 Market Value of Wisconsin Power & Light Plants

Unit Name	% Ownership	Installation Date	Type	Capacity	Market Value ($Millions)	Market Value ($/Kw)
Rock River 4	100%	12/1/1968	GTgo	16	2	150
Rock River 3	100%	8/1/1967	GTgo	26	4	150
Sheepskin 1	100%	6/1/1971	GTgo	37	6	150
Rock River 5	100%	6/1/1973	GTgo	53	8	150
Rock River 6	100%	6/1/1973	GTgo	53	8	150
South Fond Du Lac 3	100%	5/1/1994	GTgo	83	12	150
South Fond Du Lac 1	100%	5/1/1993	GTgo	84	13	150
South Fond Du Lac 2	100%	5/1/1994	GTgo	85	13	150
South Fond Du Lac 4	100%	5/1/1996	GTgo	87	13	150
Kewaunee	41%	6/1/1974	NU	498	49	242
Stoneman 1	100%	1/1/1959	STc	15	8	526
Stoneman 2	100%	1/1/1959	STc	33	17	526
Edgewater 3	100%	1/1/1951	STc	76	43	561
Nelson Dewey 1	100%	1/1/1959	STc	113	55	484
Nelson Dewey 2	100%	1/1/1962	STc	113	58	516
Edgewater 4	68%	12/1/1969	STc	342	174	747
Edgewater 5	75%	3/1/1985	STc	402	235	781
Columbia 1	46%	5/1/1975	STc	525	173	712
Columbia 2	46%	4/1/1978	STc	525	172	711
Blackhawk 3	100%	1/1/1947	STg	29	-	-
Blackhawk 4	100%	1/1/1949	STg	29	-	-
Rock River 1	100%	1/1/1954	STg	82	4	44
Rock River 2	100%	1/1/1955	STg	82	2	24
Total:					1,069	

E.3.4 Market Value of Wisconsin Public Service Plants

Unit Name	% Ownership	Installation Date	Type	Capacity	Market Value ($Millions)	Market Value ($/Kw)
Weston 31	100%	3/1/1969	GTgo	20	3	150
West Marinette 32	100%	4/1/1973	GTgo	40	6	150
West Marinette 31	100%	6/1/1971	GTgo	41	6	150
Weston 32	100%	6/1/1973	GTgo	49	7	150
West Marinette 33	100%	5/1/1993	GTgo	77	12	150
WPS Diesels	100%	1/1/1964	ICo	8	1	150
Kewaunee	41%	6/1/1974	NU	498	50	242
Edgewater 4	32%	12/1/1969	STc	342	81	747
Columbia 1	32%	5/1/1975	STc	525	119	712
Columbia 2	32%	4/1/1978	STc	525	119	711
Pulliam 4	100%	1/1/1947	STcg	26	6	218
Pulliam 3	100%	1/1/1943	STcg	28	6	218
Pulliam 5	100%	1/1/1949	STcg	50	11	218
Weston 1	100%	1/1/1954	STcg	58	14	246
Pulliam 6	100%	1/1/1951	STcg	71	23	324
Pulliam 7	100%	1/1/1958	STcg	86	46	531
Weston 2	100%	1/1/1960	STcg	88	45	514
Pulliam 8	100%	1/1/1964	STcg	137	91	664
Weston 3	100%	4/1/1982	STcg	333	228	686
Total:					874	

Appendix F. Glossary of Terms

Available Economic Capacity Test (AEC Test). The market concentration test performed in accordance with the FERC Screen. The AEC test assumes that market participants are required to withhold a portion of their least-cost capacity from the wholesale market to satisfy their native load obligations, and other long-term wholesale contracts. Only the remaining capacity is counted in the computation of structural indices. The AEC test can be interpreted as representing the short-term capacity market.

Bertrand-Nash Equilibrium. Economic equilibrium achieved by strategic suppliers competing on price but not attempting to withhold output. Usually results in the perfectly competitive market outcome. Hardly achievable in electricity markets because electricity cannot be stored in large quantities.

Capacity Withholding. Capacity withholding involves firms removing some of their capacity from the bidding process or from the market for a certain period of time, in an effort to cause more expensive units in the system to set the market clearing price. As is the case with strategic bidding, capacity withholding strives to increase the market-clearing price. Unlike strategic bidding, capacity withholding changes the merit order in which units are dispatched.

COMPEL. A computer model for simulating strategic behavior of generation owners in deregulated power markets developed by Tabors Caramanis & Associates under the grant from the National Science Foundation.

Competitive Fringe. Electricity supplies form the outside of the market areas and/or representing competitive price-taking suppliers.

Cournot-Nash Equilibrium. Economic equilibrium achieved by strategic suppliers attempting to maximize profits through withholding output and thus influencing market clearing prices. Results in very high equilibrium prices in markets with low price elasticity of demand.

Economic Capacity Test (EC Test). The market concentration test performed in accordance with the FERC Screen. The EC test presumes that there is no native load obligation in the destination market or in surrounding markets, such that all market participants are allowed to sell any portion of their power on the wholesale market. The EC test can be interpreted as representing the long-term capacity market.

GE MAPS. GE-MAPS is a powerful production cost model developed by General Electric. It simulates the physical operation of the transmission system as well as the operation of individual generating units. The ability of GE MAPS to model the detailed operation of the generation and transmission systems distinguishes it from other production cost models.

Herfindahl-Hirschmann Index (HHI). A specific indicator of market concentration calculated according to the Department of Justice/Federal Trade Commission Merger Guidelines. The HHI is the sum of the squared market shares (percentages) of each of the market participants.

Market Power. The ability of a seller to maintain prices above competitive levels for a significant period of time.

Market Concentration. An indicator measuring the effective umber of competitors of equal size operating in a market (see also HHI).

Nash Equilibrium. A game theoretical concept widely used in the economic theory of market competition. Nash equilibrium represents a set of strategies such that if any market participant deviates from the equilibrium strategy while all other participants adhere to their respective equilibrium strategies, the pay-off (e.g. profit) of the deviating market participant may only decrease. (See also *Bertrand-Nash Equilibrium, Cournot-Nash Equilibrium* and *SFE*)

Price Cost Margin Index (PCMI). A measure of the degree to which the actual price of a product in a market differs from the estimated price of that product in a “perfectly competitive” market.

Standard Offer Service. Retail service offered by the local distribution company to those electric customers who are not willing to switch to third party suppliers. Standard Offer Services could be used to protect consumers from the potential market power abuse. If properly designed, Standard Offer Service could help to mitigate market power.

Stranded Costs (Benefits). Costs or benefits that could result from deregulation of utility assets and selling-off those assets at market price. Market price below the book value of the asset results in stranded costs. Market price above the book value of the asset results in stranded benefits.

Strategic Behavior. General term referring to operations of market participants attempting to influence market prices to their advantage.

Strategic Bidding. Strategic bidding involves generating firms bidding prices above the variable production costs of their units, with the intent of forcing the market clearing price above competitive levels. Generating companies may be able to bid their units into the market at prices significantly above the variable production costs, while maintaining the merit order and often at no risk of being undercut by competitors.

Strategic Supplier. Generation owner or supplier engaged in *Strategic Behavior*.

Supply Function Equilibrium. An innovative *Nash Equilibrium* concept originally developed by Klemperer and Meyer (1989) as a way of modeling how competitors could achieve profit-maximizing equilibria in the marketplace under conditions of uncertain demand. The SFE approach was then adopted by Green and Newbery (1992) as a model for strategic bidding in a competitive spot market for electricity.